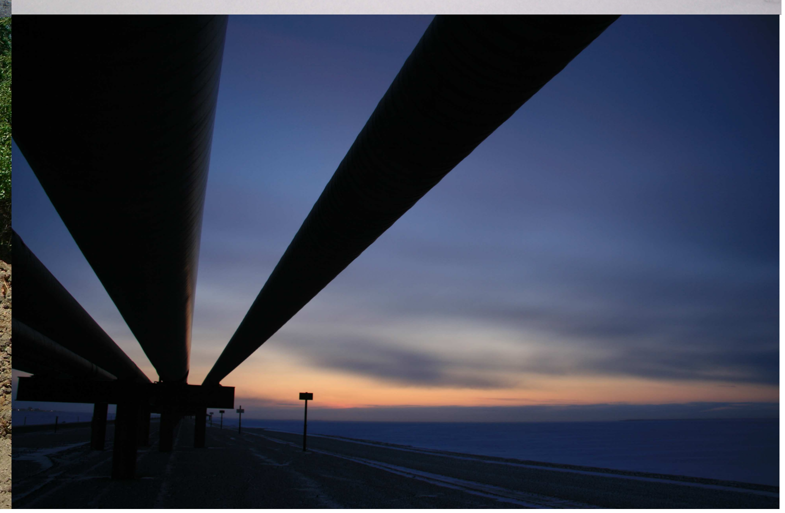
State Pipeline Coordinator's Office



Annual Report

Fiscal Year 2009

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Executive Summary

The Joint Pipeline Office is an intergovernmental organization dedicated to overseeing the safe and reliable transportation of petroleum and natural gas products to market while promoting the protection of public health and safety and the environment. The State Pipeline Coordinator's Office is an agency within the Alaska Department of Natural Resources that is co-located in the Joint Pipeline Office. Pipeline right-of-way leases that are issued by the State of Alaska under Alaska Statute 38.35 fall under the jurisdiction of the State Pipeline Coordinator and are administered by the State Pipeline Coordinator's Office.

The fiscal year 2009 State Pipeline Coordinator's Office Annual Report describes the status of jurisdictional pipeline right-of-way leases. This report integrates information from all State Pipeline Coordinator's Office activities and summarizes the prior calendar year's construction, operations, and maintenance activities on jurisdictional pipeline rights-of-way. The sections of this report include an overview of each jurisdictional pipeline, a summary of the annual reports submitted by the lessees, and a description of SPCO oversight programs and SPCO activities during the fiscal year 2009. This report does not provide a comprehensive record of all activities that are undertaken as part of the lessee's pipeline systems management; rather, this report highlights certain information and activities in order to demonstrate the implementation of SPCO lease oversight.

The pipeline ROW leases for SPCO jurisdictional pipelines require that the lessees submit annual reports compiled for the previously concluded calendar year. The 2009 fiscal year began July 1, 2008 and ended June 30, 2009, and therefore this report includes information from the 2008 calendar year's construction, operations, and maintenance activities on the ROW leases.

The FY06, FY07 and FY08 annual reports are available at the JPO website http://www.jpo.doi.gov/Publications/publications.htm

This report is intended for use by the public, government agencies, pipeline lessees, and other interested parties.

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Acronyms and Abbreviations

AAC	Alaska Administrative Code
ACMP	Alaska Coastal Management Program
ACF	Alpine Central Facility
ACS	Alaska Clean Seas
ADF&G	Alaska Department of Fish & Game
ANGDA	Alaska Natural Gas Development Authority
ANGTS	Alaska Natural Gas Transport System
AO	Authorized Officer (BLM)
APC	Alpine Pipeline Company
APSC	Alyeska Pipeline Service Company
AS	Alaska Statute
ASH	Alaska Safety Handbook
ATC	Alpine Transportation Company
BEAR	Behavior Eliminates All Risk
BLM	Bureau of Land Management
bopd	barrels of oil per day
BPTA	BP Transportation (Alaska) Inc.
BPXA	BP Exploration (Alaska)
BTEX	Benzene, Tolulene, Ethylbenzene, Xylene
BTT	Biological Treatment Tanks
BWT	Ballast Water Treatment
CAH	Central Arctic Herd
CFP	Central Facilities Pad
CFR	Code of Federal Regulations
CIC	Corrosion Inspections and Chemical Group
COTS	Corrected on the Spot
COTU	Crude Oil Topping Unit
CP	Cathodic Protection
CPAI	ConocoPhillips Alaska, Inc.
CPC	ConocoPhillips Company
CPF	Central Processing Facility
C-Plan	Oil Spill Discharge Prevention and Contingency Plan
CPS	Central Power Station
CY	Calendar Year
DCOM	Division of Coastal and Ocean Management
DEC	(Alaska) Department of Environmental Conservation
DNR	(Alaska) Department of Natural Resources
DOG	Division of Oil and Gas
DOLWD	(Alaska) Department of Labor & Workforce Development
DOT/PF	Alaska Department of Transportation and Public Facilities
DPS	(Alaska) Department of Public Safety
EA	Electrification and Automation
EPA	U.S. Environmental Protection Agency
FGL	fuel-gas line
FLIR	Forward Looking Infrared
FOSC	Federal On-Scene Coordinator
FY	Fiscal Year
GPB	Greater Prudhoe Bay
H2S	hydrogen sulfide

Acronyms and Abbreviations, continued.

HSE	Health, Safety and Environment
HSM	Horizontal Support Member
HVE	Happy Valley Extension
IAEI	International Association of Electrical Inspectors
ILI	In-Line Inspection
IMP	Integrity Management Program
IMT	Incident Management Team
JPO	Joint Pipeline Office
KE	Kasilof Extension
KKPL	Kenai Kachemak Pipeline
KPE	Kuparuk Pipeline Extension
KPL	Kuparuk Pipeline
KRU	Kuparuk River Unit
KTC	Kuparuk Transportation Company
kW	Kilowatt
LEFM	Leading Edge Flow Meter
LEL	Lower Explosive Limit
LIDAR	Light Detection and Ranging
LUP	Land Use Permit
LWC	Low Water Crossing
MAD	Mutual Aid Drill
MAG	Mitigation Advisory Group
MFL	Magnetic Flux Leakage
MLR	Mainline Refrigeration
MLU	Mainline Unit
MOA	Memorandum of Agreement
MOP	Maximum Operating Pressure
MOU	Memorandum of Understanding
MPI	Main Production Island
mW	Megawatt
NEC	Nation Electrical Code
NGL	Natural Gas Liquids
NNGP	Nuiqsut Natural Gas Pipeline
NPDES	National Pollutant Discharge Elimination System
NSB	North Slope Borough
OCC	Operations Control Center
OCMS	Operations Compliance Management System
ODPCP	Oil Discharge Prevention and Contingency Plan
OMS	Operations Material Site
OPL	Oliktok Pipeline
OSHA	Occupational Safety and Health Administration
OTL	Oil Transit Line
P&CM	Pipeline and Civil Maintenance
P&M	preventative and mitigative measures
PHMSA	Pipeline and Hazardous Materials Safety Administration
PIO	SPCO Public Information Officer
PIT	pipe integrity testing
PLMP	Pipeline Milepost
PM	Preventative Maintenance

Acronyms and Abbreviations, continued.

PS	Pump Station
PSI	pounds per square inch
PSIO	Pipeline Systems Integrity Office
PWS RCAC	Prince William Sound Regional Citizens Advisory Council
QAP	Quality Assurance Program
RCA	Regulatory Commission of Alaska
RCM	Reliability Centered Maintenance
RGV	Remote Gate Valve
ROW	Right-of-Way
RPS	TAPS Response Planning Standard
RSA	Reimbursable Service Agreement
S/D	Shut Down
SCADA	Supervisory Control and Data Acquisition
SDI	Satellite Drilling Island
Sec.	Section
SFMO	State Fire Marshal’s Office
SIPPS	Safety Integrity Pressure Protection System
SME	Subject Matter Expert
SMP	Surveillance and Monitoring Program
SOSC	State On-Scene Coordinator
SPC	State Pipeline Coordinator
SPCO	State Pipeline Coordinator’s Office
SR	Strategic Reconfiguration
Stip.	Stipulation
SWD	Solid Waste Disposal
TAGS	Trans-Alaska Gas System
TAPS	Trans-Alaska Pipeline System
TG	Turbine Generator
TWUP	Temporary Water Use Permit
ULSD	Ultra-Low Sulfur Diesel
USACE	U.S. Army Corps of Engineers
USCG	U.S. Coast Guard
USDOT	U.S. Department of Transportation,
USFWS	US Fish and Wildlife Service
UT	Ultrasonic
VFD	Variable-Frequency Drive
VMT	Valdez Marine Terminal
VPP	Voluntary Protection Program
VSM	Vertical Support Member
WSS	Walking Speed Survey
YPC	Yukon Pacific Corporation

1.0 INTRODUCTION

1.1 Federal/State Joint Pipeline Office (JPO)

The Joint Pipeline Office (JPO) was established in 1990 with the mission statement, "*To work proactively with Alaska's oil and gas industry to safely operate, protect the environment, and continue transporting oil and gas in compliance with legal requirements.*" The JPO Executive Council, consisting of executive representatives from each JPO parent agency, authorizes the Operating Agreement for the JPO on a periodic basis.

The state authorized its participation in the current structure of the JPO through the Alaska Department of Natural Resources (DNR) under the authority granted by Article III of the Alaska Constitution and by AS 44.17.060. The first Cooperative Agreement between the Bureau of Land Management (BLM) and the DNR for formation of the joint office was finalized on March 9, 1990. In July 1990, state and federal agencies agreed to work together cooperatively as the Joint Pipeline Office.

The JPO is an umbrella organization of state and federal agencies responsible for regulation and oversight of the TAPS, and other non-infield oil and gas pipelines in Alaska. The JPO was formed to provide better service to the public and industry by eliminating duplication of work; coordinating activities; improving communication between agencies, industry, and the public; sharing expenses; and streamlining the permitting process.

While all agencies retain their individual authorities, agencies collaborate and frequently work as a team on administrative, technical, and regulatory issues regarding jurisdictional oil and gas infrastructure. Agency personnel participate in self-directed work teams, such as the Oil Spill Team and the Integrity Management Team. Agencies coordinate activities such as permitting and field oversight, as needed.

The JPO is comprised of staff with technical expertise in land management, engineering, geophysics, fish and wildlife biology, safety codes, electrical codes, fire codes and oil spill planning and response. Cumulatively, the JPO technical staff has decades of experience specific to pipeline oversight.

In 2008, the state and federal agencies comprising the JPO entered into a new Operating Agreement. The Operating Agreement clarified roles and responsibilities in a complex interagency environment where multiple authorities overlap. The Executive and Operational Agreements and attachments are available for review on the JPO website: http://www.jpo.doi.gov.

1.2 State Pipeline Coordinator's Office (SPCO)

Alaska's development of its natural resources is anchored by oil and gas exploration and production. Oil, gas and utility pipelines provide the transportation infrastructure necessary to deliver these products to market. The Alaska Department of Natural Resources, State Pipeline Coordinator's Office (SPCO) is the lead agency for administering the pipeline Right-of-Way (ROW) leasing process and coordinating pipeline regulatory oversight for jurisdictional pipelines. Lease and regulatory compliance for many pipelines in Alaska is accomplished in coordination with agencies through the JPO.

The Right-of-Way Leasing Act (AS 38.35) sets forth the procedures governing an application for a pipeline ROW across state lands. Under this Act, the DNR Commissioner is granted all powers necessary to lease State land for pipeline ROW purposes.

The State of Alaska's policy, as set out in AS 38.35.010, is that development, use, and control of a pipeline transportation system make the maximum contribution to the development of the human resources of this state, increase the standard of living for all its residents, advance existing and potential sectors of its economy, strengthen free competition in its private enterprise system, and carefully protect its incomparable natural environment. The DNR Commissioner has been given all powers necessary and proper to implement this policy and to issue leases of State land for pipeline rights-of-way, to transport products under conditions prescribed by AS 38.35.015 and the associated administrative regulations.

The ROW Leasing Act requires consideration of the applicant's technical capability to protect state and private property interests. The State of Alaska's property interests at stake are the state transportation system and lands over which the pipeline will pass. The most significant manner in which the applicant will protect such state property interests is through the design, construction, operation, and maintenance of a safe and environmentally sound pipeline system.

The ROW lease between the State of Alaska and the lessee covers a wide range of activities and governs the conduct between the parties. The lease covers the full life of the pipeline: construction, operations, maintenance, and termination. The underlying theme throughout the lease is protection of human health, safety and the environment, established by safe pipeline operations and mitigation of environmental impacts.

Each lease is generally structured to address these themes. The lease sections cover several general terms, most of them legal or administrative. The terms are both substantive and procedural, and govern the relationship and interaction between the State of Alaska and the lessee.

Each lease also incorporates a comprehensive set of stipulations that impose objective environmental and technical conditions on the lessee in order to assure that the pipeline activities are conducted in a safe manner that complies with the lease, applicable laws, and regulations. The stipulations also require each lessee to establish specific processes, programs, and systems for pipeline operations. The implementation of these programs and systems helps to insure the integrity of the pipeline and pipeline operations.

Many sections and stipulations of a lease impose requirements that are the same as, or are overlapped by legal requirements of state and/or federal laws and regulations, and thus administered and enforced by separate regulatory agencies. In cases where another regulatory agency's program monitors and enforces compliance with requirements that include the requirements of a specific lease section or stipulation, the SPCO relies primarily on that agency's focused, regulatory enforcement to assure compliance with the included lease requirements. This reliance further limits duplication of efforts while utilizing the subject matter expertise of each regulatory agency to best effect.

Through reimbursable service agreements (RSA), the SPCO co-locates staff from the DNR, Division of Coastal and Ocean Management (DCOM); Alaska Department of Fish and Game (ADF&G), Alaska Department of Environmental Conservation (DEC), Alaska Department of Labor and Workforce Development (DOLWD); and the Alaska Department of Public Safety (DPS), State Fire Marshal's Office (SFMO). Appendix B, the SPCO Staff Organizational Chart, provides a visual illustration of the DNR SPCO staff resources, while Appendix C depicts the functional structure of the JPO. In addition to performing regulatory functions, each agency provides the State Pipeline Coordinator (SPC) and the BLM Authorized Officer (AO) technical expertise in the adjudication of state lease and federal grant requirements.

The DNR component of the SPCO operating structure is functionally organized in four primary sections, Engineering, Lease Compliance, Right-of-Way and Permits, and Administration (Appendix B). The roles and responsibilities of each section and each of the participating state agencies are briefly described below.

1.2.1 Engineering Section

The Engineering Section has three main goals: to provide technical oversight of facilities, equipment, infrastructure, and activities on pipeline leases; to provide engineering assistance to the SPCO and liaison agencies; and to provide engineering recommendations to the DNR Commissioner and the SPC.

The Engineering Section is responsible for verifying that certain technical requirements of each ROW lease are met. In particular, the Engineering Section's work ensures that "the applicant has the technical and financial capability to protect state and private property interests[1]," that the lessee "maintain the leasehold and pipeline in good repair[2]," and that the Lessee "promptly repair or remedy any damage to the leasehold[3]."

Leases also require that each lessee conform to applicable technical codes and regulations. The Engineering Section performs code reviews and participates in the preparation of design basis for pipelines. The Section also coordinates with other

[1] AS 38.35.100 (2)

[2] AS 38.35.120 (8)(A)

[3] AS 38.35.120 (8)(B)

agencies to provide technical assistance, if requested, and recommends whether a Lessee has the technical capabilities to build, operate, and maintain pipelines.

1.2.2 Lease Compliance Section

The SPCO Lease Compliance Section (Compliance Section) was reorganized in fiscal year 2008 (FY08). It performs oversight for all SPCO jurisdictional pipeline ROW leases authorized under AS 38.35. The Compliance Section monitors lessee compliance with lease criteria. In support of this goal, the Compliance Section works closely with the Engineering and the ROW and Permits Sections within the SPCO, as well as other state agencies, federal agencies, lessees, and operators. The Compliance Section confirms each Lessee's compliance with their Lease to verify that each ROW is managed in a manner that ensures safety and environmental awareness.

Several state and federal agencies exercise authority over aspects of SPCO jurisdictional pipelines and their ROW leases. When other agencies have primary regulatory authority, the Compliance Section coordinates with those agencies to substantiate compliance with applicable regulations, as well as Lease requirements. For lease sections and stipulations where the SPCO has primary authority, the Compliance Section verifies adherence to the lease through surveillance reports and assessments. Compliance team members conduct fieldwork throughout the year and maintain an open dialog with lessees, periodically checking documentation, procedures, and programs.

1.2.3 Right-of-Way and Permits Section

The SPCO Right-of-Way and Permits Section (ROW Section) processes ROW lease applications and amendments, implements public processes (as outlined in state statute), issues project-specific authorizations, administers rental and other payments, reviews letters of non-objection, and performs other functions as necessary. The ROW Section manages ROW lease authorizations, lease requirements, and issues various DNR permits necessary for the operations and maintenance of TAPS. DNR Natural Resource Specialists periodically conduct inspections and complete surveillance reports for operations material sites (OMS) on State of Alaska land along TAPS. AS 38.35 pipeline ROW leases and ROW lease amendments can be viewed in portable digital format at http://www.jpo.doi.gov/SPCO/SPCO.htm.

Each project can involve unique lease or permit requirements depending on several factors, including:

(1) the type of work activity,
(2) project schedule and location,
(3) land and property ownership,
(4) public comment and input,
(5) whether the project is located within a coastal zone,
(6) presence of navigable waters,
(7) water use needs,
(8) need to coordinate with other state, federal, and local agencies,
(9) public notice requirements,

(10) enforcement and jurisdictional implications,

(11) effects to habitats and wetlands,

(12) impacts to fish and wildlife,

(13) engineering and surveying standards,

(14) land appraisals, and

(15) evaluation of the potential to disturb historical sites.

As the number of factors indicates, the permit review process can involve a significant amount of coordination.

1.2.4 Administration Section

The SPCO Administrative Section provides clerical support to SPCO staff in addition to managing the administrative functions related to personnel, payroll, recruitment, budgeting, accounting, facility management, travel, property control, and the procurement of goods and services. The SPCO budget is revenue based and primarily funded via reimbursements from industry (Figure 1). State agency representatives are supported through RSA administered by the SPCO. Participation by other state agencies in pipeline oversight allows the SPCO to integrate the expertise and authority of various agencies into one coordinated office. Combined program costs for SPCO during the State of Alaska's FY09 totaled $3,814,688.

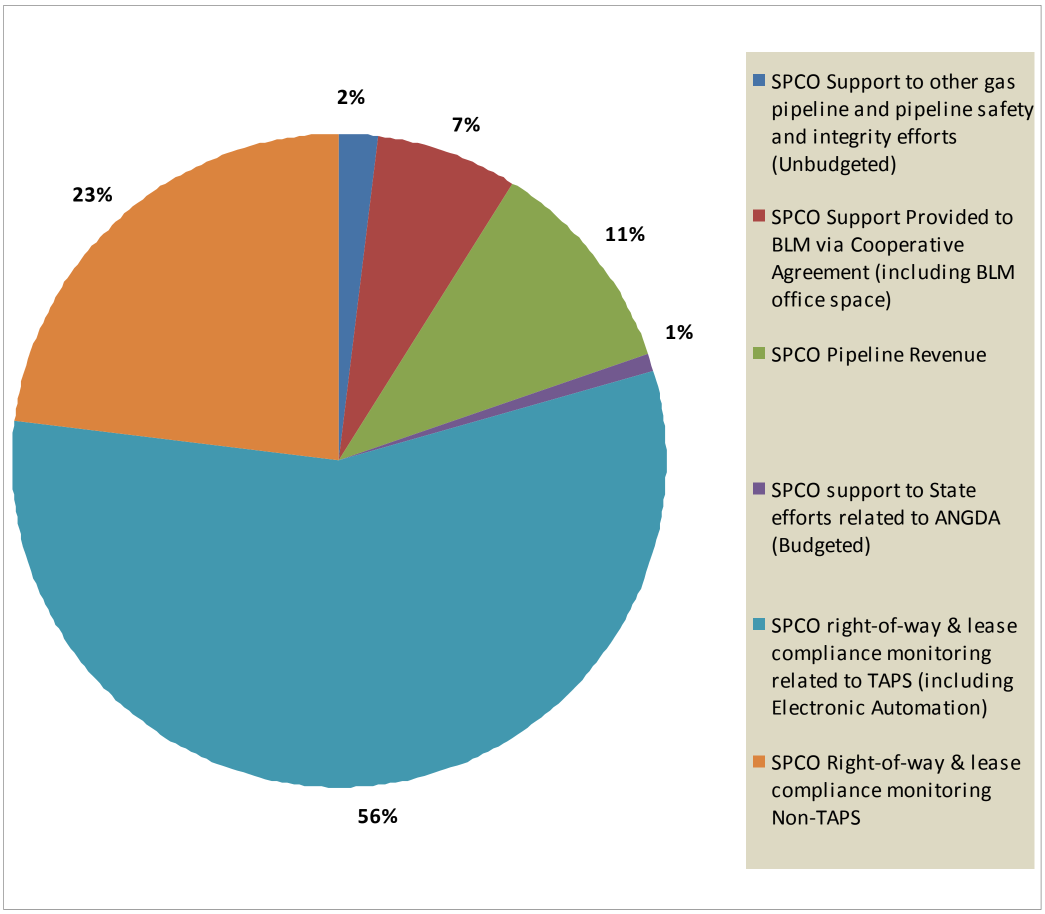

Figure 1. *SPCO FY09 Budget Expenditures - $3,814,688*

General Fund/Program Receipts, also known as pipeline revenues, are monies collected on behalf of the State by the SPCO from lease payments, material sales, and application fees. This revenue is deposited directly into the State's general fund. Each year, the Legislature appropriates some general fund monies to the SPCO which are used to support non-pipeline specific operations. In FY09 the net deposit to the State's general fund (revenue collected minus legislative appropriation to the SPCO) was $2.67 million dollars. (Figure 2).

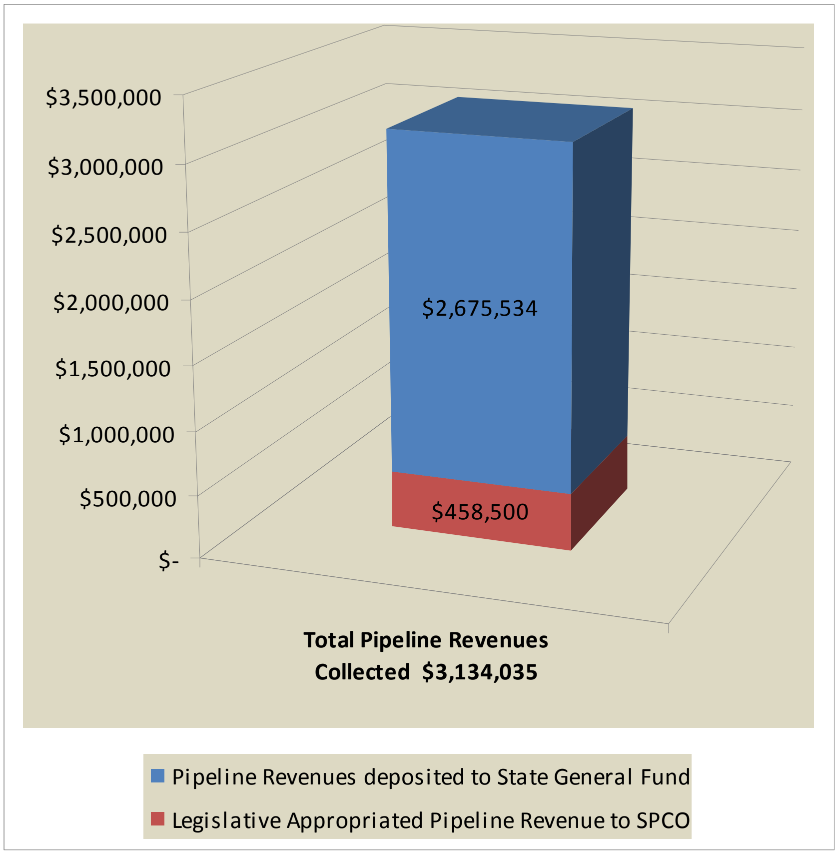

Figure 2. *SPCO General Fund Revenues: Collected vs. Expended*

1.2.5 Public Information Officer

The Public Information Officer (PIO) position is located within the State Pipeline Coordinator's Office but serves as a communications coordinator for the JPO. Pursuant to the JPO Operating Agreement, the PIO coordinated external communications for the JPO at the direction of the JPO Management Team. The position is also responsible for putting together the annual report.

The PIO position serves as the facilitator and secretary for the JPO Management Team – putting together the weekly agenda, at the direction of that group, and preparing and publishing the minutes of the weekly management team meetings. The position facilitates for other groups, including the Integrity Management Group, which is currently comprised of engineers, scientists and technical experts from the ADF&G, BLM, DEC, DNR, and the U.S. Department of Transportation (USDOT), Pipeline and

Hazardous Materials Safety Administration (PHMSA). Another such group is the Memorandum of Understanding/Memorandum of Agreement Committee (MOU/MOA) (an ad hoc group put together to review existing memoranda of understanding and agreements adopted by Alyeska Pipeline Service Company (APSC) and various JPO agency members during the organization's existence).

The PIO also interfaces on a regular basis with liaison and public relations staff from APSC. In that capacity, the PIO has worked with the SPCO Information Systems Section to improve communications of critical reports. These reports included Operations Control Center (OCC) event notifications, reports that track activity at the Valdez Marine Terminal (VMT), and oil throughput information. Members of the JPO management team, work groups, and engineers, through a dedicated JPO email account, JPO Reports, can now reliably receive these reports. The PIO also works with APSC staff to review and update a matrix that tracks reporting dates and contacts for preparation of the MP166 annual reports. These are engineering reports that address critical aspects of operations of the TAPS and are prepared by APSC over the course of the calendar year. These reports are used in the preparation of the SPCO Annual Report.

The PIO is also responsible for providing regular updates of JPO activities for JPO stakeholders. A newsletter, *Coming Down the Pipe*, is published every other Friday. The newsletter reports on topical matters related to JPO activities from all participating state and federal agencies, sections and workgroups (as well as related and relevant information from other groups, including the Alaska Department of Natural Resources and the Office of the Federal Coordinator). The newsletter is archived and available on the JPO website (http://www.jpo.doi.gov).

1.3 SPCO Liaison/State Agency Representatives

Other state agencies participating within the SPCO are assigned primarily to the oversight of TAPS and are briefly described below.

1.3.1 Alaska Department of Environmental Conservation (DEC)

The broad mission of DEC is to conserve, improve, and protect Alaska's natural resources and environment and to control water, land, and air pollution to enhance the health, safety, and welfare of the people of the state and their overall economic and social well-being. As a participating member of the JPO, and as a SPCO liaison agency, the DEC accomplishes its mission through implementing state statutes and regulations governing jurisdictional pipelines and facilities throughout Alaska. Three full-time DEC positions are co-located within the SPCO: a designated DEC Liaison who provides overall coordination as well as specific technical and policy advice and two Environmental Program Specialists whose duties center on oversight of oil spill prevention and response readiness.

The DEC liaison provides coordination and policy guidance regarding implementation of requirements of the Air Quality, Water, and Environmental Health Divisions of DEC. These divisions within the DEC oversee wastewater operations and permits, solid waste operations and permits, air quality permits, water quality permits and management of contaminated sites. The DEC liaison works with SPCO staff to ensure authorizations or permits from the SPCO are consistent with DEC statutes and regulations. The DEC liaison is also a member of the JPO Management Team.

The DEC's two Environmental Program Specialists focus exclusively on oil discharge prevention and contingency plan (C-Plan) requirements for the TAPS Pipeline and VMT. These positions work for the DEC Spill Prevention and Response Division, Industry Preparedness Program. They review and approve recommendations for the Pipeline and VMT C-Plans and ensure oversight for compliance with DEC's prevention regulations. Oversight of C-plan activities includes conducting facility and response equipment inspections, records audits, and conducting and evaluating oil spill response exercises. DEC's prevention regulations specify multiple performance and industry standards for facility piping, crude oil storage tanks, secondary containment, and the TAPS mainline. For technical analysis of compliance with prevention regulations, the Environmental Program Specialists are actively supported by the DEC Industry Preparedness Program's licensed professional engineering staff.

1.3.2 Alaska Department of Labor and Workforce Development (DOLWD)

The DOLWD has two positions in SPCO a Safety Liaison and an Electrical Inspector. At this time, these positions mainly address issues regarding TAPS.

The DOLWD Safety Liaison serves as the SPCO Program Manager on worker safety and DOLWD technical and policy objectives. This position conducts annual safety inspections of TAPS facilities, conducts worksite safety inspections, reviews project safety plans, monitors APSC accident statistics, and consults with JPO staff on employee safety issues. This position also serves as the SPCO Safety Manager, conducting safety training for JPO staff and maintaining the JPO safety manual.

The DOLWD Electrical Inspector serves as the SPCO Program Manager on compliance with electric issues, electrical licensing requirements, and DOLWD technical and policy objectives related to electrical installation. This position conducts electrical inspections of new construction and modification of existing electrical systems and consults with JPO staff and APSC on electrical issues.

The DOLWD Electrical Inspector is a member of The International Association of Electrical Inspectors (IAEI), and attends meetings and training provided by the IAEI. He regularly participates in continuing education training to stay current on the requirements of the Nation Electrical Code (NEC). He maintains current licenses as a Journeyman Electrician, which is called a Certificate of Fitness, and is licensed as a State of Alaska Electrical Administrator.

1.3.3 Alaska Department of Natural Resources - Division of Coastal and Ocean Management (DNR/DCOM)

The DNR has a liaison from the Division of Coastal and Ocean Management at the SPCO. The Alaska Coastal Management Program (ACMP) provides stewardship for Alaska's rich and diverse coastal resources to ensure a healthy and vibrant Alaskan coast that efficiently sustains long-term economic and environmental productivity

The ACMP liaison to the SPCO coordinates the State of Alaska's review of onshore oil and gas exploration and development projects and common carrier pipelines for consistency with the ACMP. The ACMP liaison works closely with state/federal/coastal district agencies to coordinate consistency reviews and properly implement the ACMP, as well as assist them in coordinating their internal procedures with the consistency review process. The ACMP liaison provides aid to representatives of local, state, and federal governments, industry (applicants), and public by assisting them with the permitting process. On behalf of the SPCO, the ACMP liaison typically coordinates coastal zone reviews of new construction and routine maintenance and repair activities for the TAPS and associated pipelines.

1.3.4 Alaska Department of Fish & Game (ADF&G)

The ADF&G liaison acts as staff assistant to the Director of the Habitat Division of ADF&G for the TAPS. The liaison administers the Fish Habitat Permit Program under AS 16.05.841 and AS 16.05.871, which includes issuing permits, conducting compliance inspections (using SPCO surveillance procedures), and taking enforcement actions, when necessary. The ADF&G liaison revises and reissues programmatic permits for low water crossing (LWC) maintenance, vehicle stream crossings, and oil spill training using approved methods and devices (i.e. temporary dams, inclined culverts, or under/overflow devices).

The liaison's mission is to insure that pipeline activities avoid or mitigate foreseeable impacts to fish and wildlife resources, habitats and public use of fish and wildlife. To do this the liaison works with other state and federal agencies, and APSC to review and provide input on design criteria, project plans, schedules, procedures, manuals, technical specifications, drawings, facility site selection, alignments and restoration or mitigation proposals pertaining to pipeline-related work, including: 1) pipeline pre-construction, 2) construction, 3) operation, 4) maintenance and 5) termination activities. The liaison prepares surveillances and assessments that document the lessee's compliance with environmental and other stipulations of the lease, and or, grant, reviews TAPS and VMT oil spill contingency plans, and participates in oil spill response for spills potentially impacting fish and wildlife populations or habitat.[4]

1.3.5 Alaska Department of Public Safety, State Fire Marshal's Office (SFMO)

The Fire Specialist performs four basic functions under the authority of the State Fire Marshal and the sections and stipulations of the Grant and Leases for SPCO jurisdictional pipelines. The four functions are fire inspections, construction/building inspections, building/fire system plan reviews, and other miscellaneous activities. Work in FY08 pursuant to a RSA between DNR and the DPS, led to oversight by the State Fire Marshall's Office of additional pipelines, as well as TAPS, during FY09.

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[4] ***Note**: On July 1, 2008, the duties and responsibilities for oversight of fish resources and habitats were transferred from the Alaska Department of Natural Resources, Office of Habitat Management and Permitting back to the Alaska Department of Fish and Game, Division of Habitat.*

1.4 SPCO Jurisdictional Pipelines

The SPCO monitors lease compliance for 17 existing pipelines within the State of Alaska. Table 1 provides summary information for each of the 17 pipelines. More detailed information with respect to physical characteristics of each pipeline, lease required contact information, acreage, survey, and lease information, and lease appraisals is available in Appendices, E, F, G, and H, respectively.

In addition to existing pipelines, the SPCO is involved, at various ROW permitting stages, with several proposed pipeline projects. At the time of this writing, none of these pipelines has been constructed (Table 2).

Table 1. Pipelines Subject to SPCO Monitoring and Oversight.

Issued ROW Leases	ADL #	Location	Length (Miles)*	Lessee(s)	Operating Status
Alpine Oil Pipeline	415701	North Slope	34	ConocoPhillips Company	Operating
Alpine Diesel Pipeline	415932	North Slope	34	ConocoPhillips Company	Operating
Alpine Utility Pipeline (Grant)	415857	North Slope	34	ConocoPhillips Company	Operating
Badami Sales Oil Pipeline	415472	North Slope	25	BP Transportation (Alaska)	Operations Suspended
Badami Utility Pipeline	415965	North Slope	31	BP Transportation (Alaska)	Operations Suspended
Endicott (Oil) Pipeline	410562	North Slope	26	Endicott Pipeline Company	Operating
Kenai Kachemak (Gas) Pipeline	228162	Cook Inlet	50	Kenai Kachemak Pipeline, LLC	Operating
Kuparuk (Oil) Pipeline	402294	North Slope	28	Kuparuk Transportation Company	Operating
Kuparuk (Oil) Pipeline Extension	409027	North Slope	9	Kuparuk Transportation Company	Operating
Milne Point (Oil) Pipeline	410221	North Slope	10	Milne Point Pipeline, LLC	Operating
Milne Point Products Pipeline	416172	North Slope	10	Milne Point Pipeline, LLC	Operations Suspended
Nikiski Alaska Pipeline	69354	Cook Inlet	70	Tesoro Alaska Pipeline Company	Operating
Northstar Gas Pipeline	415975	North Slope	17	BP Transportation (Alaska)	Operating
Northstar Oil Pipeline	415700	North Slope	16	BP Transportation (Alaska)	Operating
Nuiqsut Natural Gas Pipeline	416202	North Slope	14	North Slope Borough	Operating
Oliktok (Natural Gas) Pipeline	411731	North Slope	28	Oliktok Pipeline Company	Operating
Trans-Alaska Pipeline System	63574	Prudhoe Bay to Valdez	800	**	Operating

* The lengths in the table are the approximate total length of the pipeline or proposed pipeline centerline. The length of pipeline on state-leased ROW lands may be shorter. For more information about state lands in a particular pipeline, go to the section of this report for that pipeline.

** BP Pipelines (Alaska) Inc.(46.93%), ConocoPhillips Alaska Transportation Inc. (28.29%), Exxon/Mobil Transportation Company (20.34%), Unocal Pipeline Company (1.36%), Koch Alaska Pipeline Co. LLC (3.08%).

Table 2. Proposed pipelines in the ROW pre-application or application phase of development.

ROW Applications	ADL #	Location	Length/Miles	Applicant	Application Status
Alaska Natural Gas Transport System (ANGTS)	403427	n/a	n/a	Alaskan Northwest Natural Gas Transportation Company and TransCanada Alaska Company, LLC	Withdrawn (02/2008)
ANGTS (Federal)	414956	varies	294.65	Alaskan Northwest Natural Gas Transportation Company	Federal Grant (Waiver of Administration)*
Dayville Road Pipeline A Dayville Road Pipeline B Dayville Road Pipeline C	229284 229285 229286	Valdez		Petro Star Incorporated	Application
Denali - The Alaska Gas Pipeline	n/a	North Slope to Alberta	794	Denali - The Alaska Gas Pipeline, LLC	Pre-application
TransCanada/ExxonMobil	n/a	Specific route not fully determined	n/a	TransCanada/ExxonMobil	Pre-application
Eastern North Slope Oil Pipeline	417577	North Slope	45	DNR, Office of Project Management and Permitting	Application
Eastern North Slope Gas Pipeline	417578	North Slope	45	DNR, Office of Project Management and Permitting	Application
Glennallen to Palmer (Spur Gas) Pipeline	229297	Southcentral	148	Alaska Natural Gas Development Authority (ANGDA)	Conditional lease issued on July 20, 2006
Amendment to the Glennallen-Palmer Pipeline	229297	Southcentral		ANGDA	Pre-application
Alaska Stand Alone Pipeline	n/a	Prudhoe Bay-Southcentral Alaska	735	State of Alaska	Pre-application
Trans-Alaska Gas System (TAGS)	413342	Prudhoe Bay to Valdez	797	Yukon Pacific Corporation (YPC)	Conditional lease terminated
Pt. Thomson Pipeline	n/a	Pt. Thomson to Prudhoe Bay		ExxonMobil Pipeline Company	Pre-application
TAGS	415224	varies	797	YPC	Federal Grant (Waiver of Administration)

*(Federal Grant administered by DNR)

2.0 Statewide Pipelines

2.1 Trans-Alaska Pipeline System (TAPS)

Figure 3. *North of Fairbanks, a section of TAPS is surrounded by fireweed.*

2.1.1 Right-of-Way Lease and Pipeline System Overview

Oil was discovered at Prudhoe Bay in 1968. The owner companies operating at Prudhoe Bay established the Alyeska Pipeline Service Company in 1970 to build and operate the Trans-Alaska Pipeline System (Appendix F, Lease Required Contact Information). The State of Alaska ROW Lease Agreement for TAPS was executed May 3, 1974, and renewed for another 30 years on November 26, 2002 (Appendix G, Acreage, Survey, and Lease Information). Today the owner companies, or Lessees, consist of the following: BP Pipelines (Alaska) Inc. (46.93%), ConocoPhillips Alaska Transportation Inc. (28.29%), Exxon/Mobil Transportation Company (20.34%), Unocal Pipeline Company (1.36%), and Koch Alaska Pipeline Co. LLC (3.08%).

The Lease applies to the approximately 344 miles of State of Alaska owned land in the TAPS ROW. Approximately 376 miles of federal lands and 80 miles of private lands (including Native Corporation and Native Allotment lands) account for the remainder of the 800-mile ROW. APSC owns 8.2 miles of ROW, primarily consisting of lands associated with Pump Stations (PS) 1, 8 and 9 and the Valdez Marine Terminal.

TAPS was originally comprised of an 800-mile, 48-inch-diameter pipeline, the VMT, 11 pump stations (original plans specified 12 pump stations, only 11 were actually constructed), and various support facilities (Appendix E, Physical Characteristics of SPCO Jurisdictional Pipelines). To support construction of the pipeline, a permanent haul road was constructed from the Yukon River to Prudhoe Bay in 1974. Management of this road was transferred to the State of Alaska in 1978 and named the James B. Dalton Highway in 1981. Most of the remainder of the pipeline was supported by the existing state road infrastructure.

The TAPS has 177 pipeline valves strategically placed along the pipeline to isolate sections of the pipeline and to minimize the size of potential spills in the event of a pipe rupture. The valves are placed to limit the amount of a spill at any point to a maximum of 50,000 barrels from static drain down. Valves are placed at major river crossings and other locations where quick closure would be necessary in an emergency.

Today, four pump stations are used to pump oil, while others only have instrumentation and miscellaneous facilities. Some facilities are fully manned, some are de-manned; many were once active installations, but are now shut down because of declining throughput.

North Slope oil enters the TAPS at PS 1, located at Prudhoe Bay, immediately northwest of the community of Deadhorse, Alaska. The TAPS crosses three major mountain ranges before reaching its terminus at the VMT (Figure 4). Three of the four active pump stations (PS 1, PS 3, and PS 4) maintain the pressure necessary to pump crude oil over Atigun Pass – the highest elevation point along the TAPS at an altitude of 4,739 feet (the elevation at PS 1 is 22 feet above sea level). PS 5 provides pressure relief as crude oil descends in elevation south of Atigun Pass. PS 7 was placed in warm standby mode in 2007. The fourth active pump station, PS 9, provides the pressure necessary to push the crude oil over the Alaska Range and Thompson Pass and complete its passage to the VMT.

Figure 4. *The TAPS Tank Farm at the Valdez Marine Terminal.*

Although there are exceptions, each of the pump stations typically has facilities and equipment housed within structures for protection against the environment. The facilities at PS 1, PS 3, and PS 4 include electrical power generation, pumps, isolation valves, fuel-handling facilities, and station and support facilities. The facilities at PS 9 include all of the previously listed equipment except primary electrical generators. It obtains its electricity from a commercial grid. All of the pump station locations are fenced and security is provided at each station. A number of the originally constructed stations, such as PS 2, PS 6, PS 8, PS 10, and PS 12, have had their major equipment shut down and removed.

The VMT is the southern terminus of TAPS. The VMT site covers about 1,000 acres and is located on Prince William Sound near the Port of Valdez. At the VMT, oil is loaded onto tankers for shipment to markets. The VMT has a vapor recovery system for the crude-oil storage and relief tanks, a powerhouse, support facilities, crude storage, tanker berths, crude-oil handling systems, and metering facilities.

The TAPS facilities are maintained and upgraded on an ongoing basis. This helps to ensure safe and efficient operation and minimizes the likelihood of accidental releases. APSC conducts many types of inspections. Some inspections are visual, from either the ground or the air. In addition, maintenance pigs are launched every four days or two, and smart pigs are typically launched every three years. Inertial-guidance pigs (geopigs), which determine the spatial location of the pipeline centerline, are typically launched every five years. Inertial-guidance pigs may be combined with caliper measurements.

The oil throughput in TAPS peaked in 1988. A decline in flow rate triggered an evaluation of future operating conditions by APSC and the TAPS owners. Conceptual modifications were reported in the Final Environmental Impact Statement for the TAPS Right-of-Way Renewal in 2002 and a conceptual engineering review was developed in 2003. The TAPS owners (Lessees) approved changes to the pump station configurations, referred to as Strategic Reconfiguration (SR). The project name was changed to Electrification and Automation (EA) during calendar year 2009 (CY09). The work planned under the SR project was started in 2002. Although there is no firm time estimate for completion of this project, it is likely to be finished by middle of 2013. The benefits of SR include increased flexibility in adapting to changes in crude oil transportation through the TAPS, equipment better sized for the reduced TAPS throughput, technological improvements, greater automation, and optimization of support infrastructure and resource utilization.

2.1.2 TAPS Annual Reports Overview

Annually, APSC submits a number of reports to the JPO that address the APSC monitoring programs. These reports are directly tied to various agreements and stipulations pertaining to the TAPS Grant and Lease. Of particular interest to the SPCO are seven Integrity Management Program (MP-166) reports. The reports are prepared, reviewed, and approved by APSC engineers.

These reports address various components of the company's operations and efforts to monitor the integrity of the pipeline, related facilities, and conditions impacting lands, water, and other geological components connected to the TAPS ROW. These reports are divided among the following subject matters:

- Mainline Aboveground Support System and Bridges Program
- Rivers, Floodplains and Glacier Monitoring Program
- Tank Monitoring
- Right-of-Way and Facilities Civil Monitoring Program
- Pipeline and Valdez Marine Terminal Facilities Corrosion Monitoring
- Mainline Integrity Monitoring
- Fuel Gas Line

In addition, APSC submitted a follow up report called the *Alyeska Compliance Program Monitoring and Performance 2008 Summary*, which summarized the MP-166 reports.

This section is the SPCO summary of the CY08 MP-166 reports, submitted by APSC. The specific projects summarized by this section of the report represent a small sample of the asset management activities conducted by APSC. The information presented in this section is sourced or condensed mainly from the 2008 MP-166 and Integrity Management Reports prepared by APSC. A few minor sections are quoted from select APSC letters and special reports (See Section 7.0, FY09 Annual Report Major Source Documents).

2.1.2.1 APSC Annual Report – Mainline Aboveground Support System and Bridges

The aboveground monitoring program addresses monitoring and maintenance issues pertaining to the mainline aboveground pipeline support system, the pipeline bridges program, the slope stability component of the TAPS ROW, and the facilities civil monitoring program. In 2008, the aboveground maintenance program completed nearly all the routine projects identified in 2007. APSC reports that overall performance of the system is satisfactory based on their current data and that a majority of the system is in good to excellent condition.

Additional highlights of this report include the following:

There are currently no high-priority projects in this category. APSC identified the following as medium priority projects for CY09:

1) Assessing two bents (each vertical support member (VSM) and crossbeam structure is a "bent") at Squirrel Creek and determining the need for replacement;
2) Finishing their investigation of potentially liquefiable soils;
3) Various heat pipe repairs; bridge maintenance; replacement of the Little Salcha River workpad vehicle bridge;
4) Performing engineering assessments of the Gulkana and Tazlina pipeline bridges; and
5) Assessing all multi-plate aboveground road crossings.

Vertical Support Members, Horizontal Support Members, and Heat Pipes

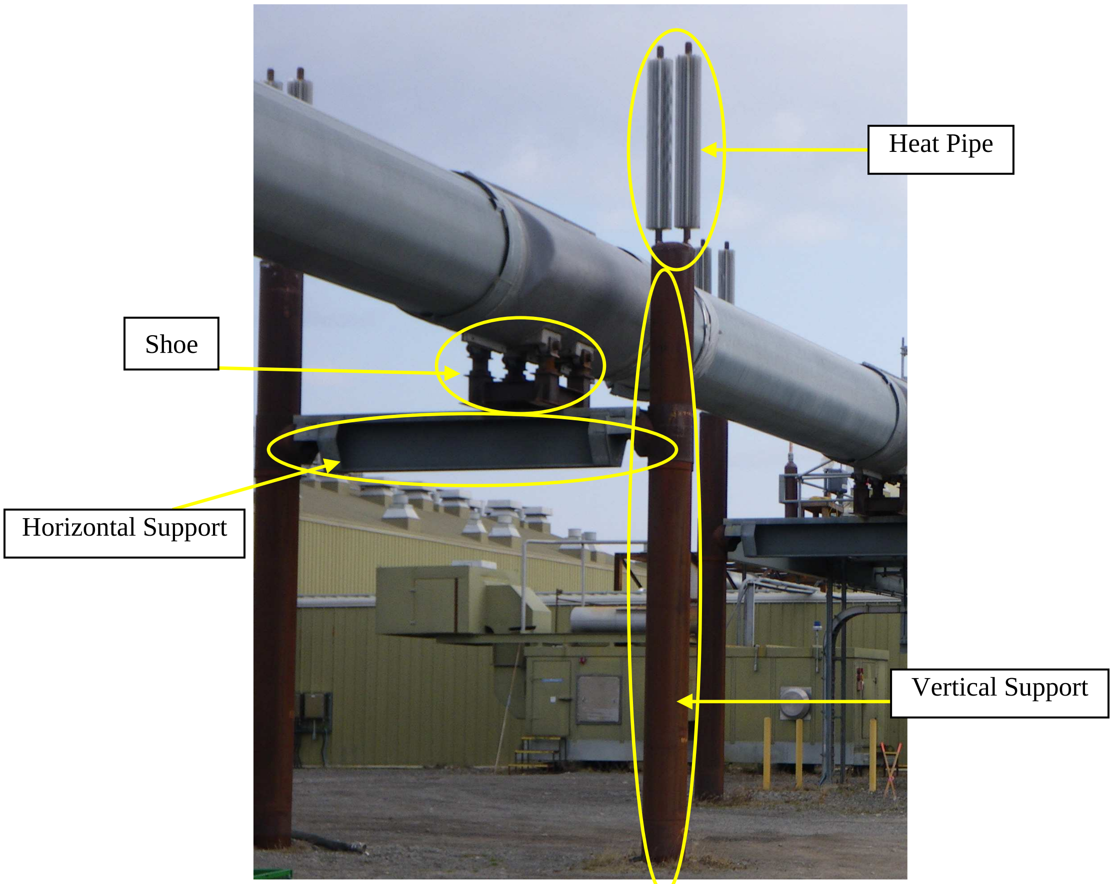

Figure 5. *An example of a VSM found at TAPS PS 3.*

As these names suggest, VSMs and horizontal support members (HSMs), are the vertical and horizontal structures supporting the aboveground portion of the TAPS mainline pipe (Figure 5 above). The VSMs are also significant because they may house the heat pipes that transfer heat from the ground up to be released into the atmosphere. About half of

VSMs are cooled by heat pipes. Heat pipes prevent the ground from rapid thaw that can cause jacking or subsidence of the VSMs.

In August 2008, a comprehensive “linewalk” was conducted, which assessed 850,000 attributes along the aboveground segments of the pipeline. A discussion of the heat pipes is included in this category, since all but 1,500 of the approximately 60,000 heat pipes monitored this year are part of the VSMs. Figure 5 and Figure 6 are examples of heat pipes found on TAPS.

During CY08, maintenance crews conducted Forward-Looking Infrared (FLIR) analysis of approximately one-third of the heat pipes in the system (A FLIR analysis, to identify damaged heat pipes, is planned for 135-140 miles of the mainline for the upcoming winter). In certain heat pipes, non-condensable gases have formed in the top of the interior, and if a large portion of the radiator section is occluded, the efficiency of heat energy transport is reduced. Approximately 2,000 heat pipes were recharged during CY08, from pipeline milepost (PLMP) 669 to PLMP 736. To date, APSC reports approximately 14,000 heat pipes converted from ammonia to carbon dioxide.

APSC reports no progress on its program to replace Getter Pins. Getter Pins are tapered steel pins containing zirconium dimanganese that absorb hydrogen. Hydrogen inhibits the heat-transfer exchange in the heat fins atop the VSMs. In 1983, APSC initiated a project to place Getter Pins on the heat pipes of the TAPS VSMs. This repair method, in general, was technically successful but abandoned when APSC decided to convert heat pipes from ammonia to a system using CO2. Approximately 15% of the Getter Pins have failed. APSC estimates that between 1,500 and 1,800 heat pipes fail annually. Their repair backlog is about 8,000 units. To give a point of comparison, approximately 122,000 heat pipes were installed on the TAPS.

Heat pipes, however, have a built-in redundancy in most locations. Other safety factors were also applied to the heat calculations and fin surface area, in addition to the redundancy. The number of heat pipes reflect an almost 100% redundancy. Numerous safety factors were applied to the heat calculations and fin surface area, on top of the 100% redundancy. Therefore, heat-pipe maintenance can be approached as a long-term, multi-year remediation effort.

Figure 6. *Heat Pipe and radiator at Squirrel Creek.*

The 2008 assessment, conducted by APSC, included an evaluation of 15,546 bents, anchors and other supports. Fifty-one out of approximately 78,000 VSM (0.000641%) exceeded a 3-degree tilt. These are being monitored by APSC engineering to evaluate if repairs are necessary. APSC notes that 272 HSMs were found to be more than one-degree out of level. None of the HSMs exceeded the six-degree repair criteria.

APSC reported continued progress on upgrading their Engineering Database Management system to include aboveground support information. No hydraulic events, large enough to move the mainline, were reported so no inspections were conducted. In addition, no wildfires threatened the pipeline ROW during this period.

Bridges

No major work on bridges was performed during this reporting period. Bridge projects scheduled for CY09 included removal of the Gulkana River Pipeline Bridge access walkway and guardrail upgrades at four sites. Figure 7 is a photograph of the Gulkana River Pipeline Bridge, before the upgrades were completed.

Figure 7. *The TAPS as it crosses the Gulkana River on a pipeline bridge.*

APSC is also evaluating condition of the Little Salcha River Bridge (PLMP 490.8) and, for the time being, is deferring the replacement of the Solomon Gulch Bridge (PLMP 797.8).

Geotechnical and Slope Stability

APSC closely monitors slope stability problems at several locations. The company identified seven slopes as candidates for laser scanning methodology, called, Light Detection and Ranging (LIDAR). New projects in this area include assessments of bents on the south slope of Squirrel Creek (PLMP 717.29) and the wood chip insulation on Klutina River Hill ROW pad (PLMP 698.02). APSC increased monitoring of the ground inclinometer (an instrument for measuring angles of slope) and thermistors (a temperature-sensing element) at Lost Creek, and of the inclinometers and the piezometer (a pressure measuring instrument) at the Glennallen Response Base.

In preparation for the 2008 Mainline Re-Route Project at PS 2, APSC shutdown mainline refrigeration at the station. The line was monitored during the time it was in use without refrigeration and little subsidence was noted. SPCO Engineering Section believes that this was because lower throughput has resulted in lower pipeline temperatures at that point and because the area has largely thermally stabilized during three decades of use.

2.1.2.2 APSC Annual Report – Rivers, Floodplains & Glacier Monitoring

The primary focus of the Rivers, Floodplains and Glacier Monitoring (Rivers and Floodplains) Program is to ensure that floods, erosion, or other changes do not pose an integrity threat to the mainline or related facilities. APSC reports that there were no findings that threaten the integrity of TAPS. The northern section of the pipeline from Hess Creek (PLMP 378) to the Sagavanirktok River basin experienced a mild spring breakup with some summer flooding. The southern section of the line from Fairbanks to Valdez experienced a mild spring breakup with occasional high water situations.

Flooding

APSC reported no major flood damage during CY08. The company characterized spring breakup and aufeis conditions along TAPS as mild to moderate (aufeis formations occur when ground water or some other water source seeps and freezes causing ice layers). There was minor damage due to aufeis formation in the Mark Creek area (PLMP 68-76). The Sagavanirktok River experienced less than average summer flooding and almost no significant bank erosion. There was moderate to average-size floods in the Dietrich and Koyukuk Rivers, resulting in bank erosion at the Dietrich River (PLMP 200) and the Koyukuk River (PLMP 208). An armored revetment is planned to mitigate and control erosion at the Dietrich River upstream of the pipeline. There were no major floods along the Delta or Tanana Rivers. The only damage requiring additional reinforcement was at the Access Road 36 and the bridge abutment on Phelan Creek (PLMP 599). Figure 8 shows the Phelan Creek Bridge.

Figure 8. *Phelan Creek, September 11, 2008.*

In the Copper River Drainage Basin, Big Iceberg Lake, formed by impounded water from Tazlina Glacier, released on August 15, 2008 causing a flood estimated to crest at a flow rate of 50,000 cubic feet per second and a peak flood stage of 31.2 feet at the Richardson Highway Bridge. The only damage to the TAPS facilities occurred when rip-rap was washed away at the north bank revetment. APSC considers the condition of the revetment to be satisfactory.

In August 2006, the southern end of the TAPS experienced flooding estimated to be of a 500-year return interval. APSC made emergency repairs that have held up well over the two years since the flooding occurred. The most prominent repairs took place at the Tonsina River and Stuart Creek. Figure 9 illustrates damage caused by the flooding.

Figure 9. *October 2006 floods -- Richardson Highway in Keystone Canyon.*

APSC completes yearly maintenance, engineering assessments, and remediation projects as part of their Rivers and Floodplains program. Glacial monitoring is also part of this program, but it is not discussed in depth here because it has been many years since any glacier movements along the TAPS ROW posed a significant threat to the mainline. The Fels, Canwell, Castner, Black Rapids, and Worthington glaciers are monitored annually to ensure that there will be forewarning, should surges threaten the integrity of the pipeline.

Erosion
The north bank of the Salcha River shows some erosion. The pipeline is buried deep at this location and there is no immediate integrity threat. Neither the Lowe River Drainage Basin nor the VMT suffered any significant damage but the gravel berm at Abercrombie Creek (PLMP 796.2) experienced more erosion at an area where the pipeline is shallowly buried. APSC repaired the damage and added rip-rap in CY09.

At Hess Creek (PLMP 378.6) rip-rap vanes were installed in 2005 as part of the Hess Creek Realignment Project to protect against erosion. During CY08 APSC noted that, despite several high-water events, the vanes functioned as designed by aligning the main channel flow with the pipeline bridge opening (Note ADF&G review of the Hess Creek Realignment project is provided in Section 2.3.7.3).

Figures 10 and 11 illustrate an example of erosion from water flow transport at Oskar's Eddy (PLMP 178.79). Oskar's Eddy is identified as a fish stream and the TAPS crossing is maintained to provide fish passage. Figure 10 shows erosion damage of the streambed and Figure 11 shows the remediation work performed by APSC.

Figure 10. *Oskar's Eddy in 2000, prior to the remediation efforts of APSC.*

Figure 11. *Oskar's Eddy in 2001, after remediation efforts by APSC.*

2.1.2.3 APSC Annual Report – Tank Monitoring

The tank maintenance and monitoring program addresses external tank inspections and authorization for expenditure for project work involving internal tank inspections. Much of the oversight and regulation of TAPS tanks is provided by DEC, mainly through provisions of Alaska Administrative Code (AAC), Title 18, Chapter 75 and associated regulations, and by the PHMSA, through enforcement of the Code of Federal Regulations (CFR) Title 49, Part 195. DEC is involved with only certain types of tanks, primarily hydrocarbon storage or relief tanks with a capacity of 10,000 gallons or above. PHMSA jurisdiction is limited to tanks that are part of the pipeline safety and relief systems, including the large tanks at PS 1, the relief tank at PS 5 and two relief tanks at the VMT.

Tank Integrity

APSC accomplished a number of projects under its tank monitoring program in CY08. Following the discovery of a leak downstream of tank 94 (located at the VMT), APSC inspected the 24-inch outlet nozzles on Tanks 93 and 94. These inspections revealed external corrosion at a girth weld and spool pieces. The cause was identified as de-icing salt-water intrusion from a leak in the snow shelters. Pipe corrosion and holes in the shelters have been repaired.

At PS 4, tank 31-TK-140 was cleaned, inspected, coated internally, and re-commissioned. No shell repair or plate replacement was necessary. Based upon the calculated corrosion rates and critical thicknesses and condition of the tank, APSC extended the inspection cycle of tank 31-TK-140 from 10 years to 20 years. The next inspection of this tank is scheduled for 2028.

At PS 9, APSC cleaned, inspected, and retired diesel storage tanks 39-TK-197 and 39-TK-198 from active service.

At the VMT, APSC worked on several tank projects. The Ballast Water Treatment (BWT) tank (51-TK-92) was cleaned, inspected, and retired from service. This was an adjunct to the BTEX (Benzene, Toluene, Ethylbenzene, and Xylene) upgrades described elsewhere in this report. APSC cleaned, inspected, and re-commissioned crude storage tank 54-TK-7. No shell repair or plate replacement was necessary. Two plate patches were added, resulting in the minimum floor thickness increasing to 0.215 inches. APSC inspected out-of-service diesel storage tank 58-TK-56. Distortions in the door sheet were noted, but a finite-element analysis determined these to be within the acceptable range. Tank 56 was returned to service in September 2008.

In 2006, DEC approved a 12-year inspection cycle for tank 54-TK-7. Based upon the calculated corrosion rates and the critical thicknesses, APSC extended the inspection cycle from 12 years to 14 years. The next inspection of this tank is scheduled for 2022. The next inspection for tank 58-TK-56 was determined to be in 2018, a ten-year interval. At PS 3, the diesel storage tank 33-TK-137 is scheduled to be removed from service in 2009.

2.1.2.4 APSC Annual Report - Right-of-Way and Facilities Civil Monitoring

The civil monitoring program addresses monitoring, maintenance and repairs performed in 2008 and engineering procedures involving fault movement and slope stability, VMT slope stability and facility monitoring. In brief, APSC reports the following. Under F*ault Monitoring*, there were no notable seismic events in the TAPS corridor. A new earthquake monitoring system was put into service in December 2008. *Slope Stability Monitoring* indicated that movement of seven slopes of interest was generally within historic rates. *Valdez Marine Terminal Slope Stability Monitoring* generated recommendations for rock scaling, rock bolt tightening, the removal of some vegetation, cleaning of weep holes and an engineering review of piezometric data for the previous four years by a consultant. Under *Facility Monitoring* APSC recommends monitoring of locations where vertical movement was noted. Some of the more significant findings are noted below.

As part of their Civil Monitoring Program, APSC conducts elevation surveys at points of interest throughout the facilities. Anomalies or exceptions were found at five areas, listed below:

- PS 1: One monitoring point on the primary generator room showed a possible heave.
- PS 3: Benchmark data on the new SR facilities was collected.
- PS 5: Manifold and liquids building monitored for vertical movement.
- PS 6: Settlement and heave continues at the Fuel Pump House. No intervention was recommended, only continued monitoring.

- PS 8: One point in the Crude Header Building may have settled up to one-half foot. However, survey error is suspected.
- VMT: The biological treatment tanks (BTT) at the VMT have experienced movements in the past. The present monitoring resulted in measured movement ranges all within the acceptable level.

Fault Monitoring
There were no large or notable earthquakes along the TAPS corridor in CY08. A new seismic monitoring system tied into the statewide grid was completed. The earlier system had monitoring stations running north to south along the pipeline that was more sensitive to ground movements in this direction. The new system, operated by the University of Alaska, Fairbanks, ties the eleven monitoring stations at APSC facilities into the State of Alaska seismic monitoring system (consisting of approximately 800 monitoring stations). This grid has stations located in other compass directions, forming an irregular "net" across the state. The Division of Geological and Geophysical Surveys, University of Alaska, Fairbanks (West Ridge) and SPCO Engineering maintain that integration of APSC monitoring equipment with the main state grid should provide faster, more accurate analyses after a seismic event and should provide more accurate information for ground movements in any direction.

Slope Stability Monitoring
During 2008, APSC monitored seven locations under a program intended to provide annual engineering evaluations. Those locations are: Lost Creek (PLMP 392); Treasure Creek Slope (PLMP 442); Glennallen Response Base Hill (PLMP 686); Tazlina River Hill (PLMP 687); Klutina River Hill (PLMP 698); Squirrel Creek North Slope (PLMP 717) and Squirrel Creek South Slope (PLMP 717.4).

No significant changes occurred during this period. Some monitoring equipment in these areas is in need of repair. APSC plans to repair and upgrade these instruments during CY09.

VMT Slope Stability Monitoring
APSC is monitoring groundwater at the VMT. Some slopes surrounding the terminal depend upon proper drainage of groundwater to ensure that no massive ground movements occur. APSC personnel monitor piezometers at slopes around the Power Plant, the Vapor Recovery System, BWT, the East and West Manifold buildings and the East and West Tank Farms. This work indicated no significant increases in ground water levels from CY07 to CY08, with one exception. The piezometer reports that values within the exception area remain at acceptable levels.

Facility Monitoring
Vertical and horizontal movement and crude heater monitoring were conducted in 2008 at the VMT BTT, as recommended by the 2007 civil monitoring report. The movement was found to be in acceptable limits. Facilities at PS 1, PS 3, PS 5, PS 6, and PS 8 were monitored in 2008. Vertical movements at the PS 5 Manifold and Flammable Liquids Buildings and at the PS 6 Fuel Pump House will require additional monitoring in 2009.

2.1.2.5 APSC Annual Report – Pipeline and VMT Facilities Corrosion Monitoring

The pipeline and VMT facilities corrosion program addresses monitoring and maintenance activities performed on piping and other structures on the TAPS, pump stations, and VMT. APSC reports that work conducted on this program in 2008 indicates that the overall health of the system is in satisfactory condition. During the reporting period, work efforts included application of corrosion inhibitor and internal corrosion monitoring, facility pipe integrity testing (PIT program), VMT berth, and underwater inspections.

APSC corrosion control and monitoring program covers the pump stations and related facilities, the mainline, the fuel-gas line (FGL) and the VMT. The FGL is discussed later on in this report. This section covers the mainline and the related major facilities but does not address the berths and tanker loading areas.

Low-Flow Corrosion

It should be noted that most of the following section on low-flow corrosion is primarily condensed from special reports and information submitted by APSC to the SPCO and other agencies. Unusual corrosion has been found in the PS 1 tank header piping. These pipes experience low velocities and intermittent flow, unlike other pipes in the TAPS system. The corrosion is located mainly, but not exclusively, on welds or at the heat-affected zones of the welds. After this discovery, there was concern that similar corrosion might be found throughout the low-flow areas of TAPS. Subsequent investigations indicate that the most significant corrosion in the system is in the piping to the large storage/relief tanks (TK-110 and 111) at PS 1.

The use of relatively new technology - an ultrasonic (UT) methodology that utilizes a combination of UT Phased Array and Time of Flight Diffraction techniques to scan the welds from the side, made the discovery of this corrosion possible. In the past, this type of corrosion was typically detected by grinding (flat-topping) the weld cap and utilizing straight-beam techniques.

Piping to the tanks is not piggable and, hence, standard ILI techniques cannot be used, making this type of corrosion difficult to find. Under the APSC facility corrosion-control program (called PITS), a weld with 20% or more wall loss requires corrective action. In certain locations, sleeves had to be added to the piping at PS 1 to remediate areas of corrosion. Nearly all of the areas of concern were internal and at the bottom of the pipe, between the four and eight o'clock positions. There are portions of the piping that are difficult to reach with the equipment used to perform direct assessment from the exterior pipe wall. Most of these areas were not inspected. APSC reports that all actionable corroded areas (under PHMSA regulations) in the piping have been remediated.

Integrity

APSC provided a detailed inventory of corrosion inspection sites and grids where they performed work. There were 381 total inspection sites (133 at PS 1 and 99 at the VMT). Inspection sites can have one or more inspection grids associated with them. The sites had 686 inspection grids (including 211 at PS 1 and 172 at the VMT), and 119 piping legs (including 56 at the VMT and 18 at PS 1).

Out of 68 mainline valves inspected, six had actionable corrosion loss, all on bypass piping. Corrosion in the actionable range was found in seven grids at the operations and material site and on 11 grids at the BWT plant, located at the VMT. Actionable corrosion items were noted at all pump stations except PS 2 and PS 5.

APSC assessed nine tanks for cathodic protection (CP) levels. Low CP potentials were noted at an insulated box at PS 1 and Tanks 137, 150, 190 and 220.

Low levels of CP were noted at the following locations:

1) points along the fuel gas piping from PS 1 to PS 4,
2) the leading edge flow meter (LEFM) corridors at PS 4 and PS 9,
3) the bypass in the Manifold Building at PS 4, the fuel line to the shop at PS 5,
4) block valve-1 at PS 7, and
5) the fuel piping at the oil spill response building at PS 6.

At the VMT, low CP levels were noted in 160 feet of crude piping, 590 feet of firewater piping, 448 feet of diesel piping and Tanks 8, 12, 15-18 and 55.

APSC stated that their CY08 integrity efforts were based upon data from the 2002 curvature/deformation ILI tool, the 2004 magnetic flux leakage (MFL) smart pig and the 2006/2007 MFL smart pig. Note: APSC completed MFL smart pig runs in November 2009.

The integrity program implemented by APSC also involves accessing the pipe in areas where the ILI devices make "calls". Whether the section is buried or above ground, the work is called "the dig program." This year the program consisted of two aboveground and four belowground investigations. These investigations resulted in repair work of four below ground locations and one above ground location.

2.1.2.6 APSC Annual Report – Mainline Integrity Monitoring

The mainline integrity monitoring corrosion program addresses monitoring and maintenance activities performed on the TAPS mainline pipeline. During 2008 work under this program focused on belowground monitoring, CP monitoring and system upgrades, and mainline integrity investigations. The mainline integrity investigations consisted of four belowground and two aboveground investigations of dents and corrosion, reviewing deformation data from a 2006/2007 mainline ILI run, installation of pipe with known machined defects for ILI inspection calibration at PS 2 (Figure 12), and an investigation of a location where flood damage was suspected. APSC reports that no adverse conditions were discovered. Additional highlights of this report include the following:

Figure 12. *A close-up look at anomalies in the new pipe segment at PS 2.*

Remote Gate Valve 72 Replacement

A remote gate valve (RGV) 72, was replaced during a scheduled pipeline shutdown in the summer of 2008 because its leak-through rate fell short of performance standards set by APSC. Figure 13 shows the replacement valve being lifted into an upright position so pipe extensions could be welded on before it was set into place, and was provided by BLM/JPO. Technicians tested RGV 72 in September 2007 and determined that the valve was not sealing as designed. APSC reported that the replacement work was successful.


Figure 13. *The RGV 72 replacement valve.*

Integrity

As part of their integrity program, APSC monitors belowground pipe stability, including curvature. Three areas were reported to have possible surface settlement: PLMP 15.8, PLMP 17.5, and RGV 33. Monitoring rods in these locations revealed little movement of the mainline pipe. The last geopig (inertial ILI device) run, in 2006, showed these areas to be stable. APSC concluded that although all three locations showed surface movement, the changes were isolated to the soils above the pipe. Small movements were reported at PLMP 224.9, mainline refrigeration unit (MLR) 2, and RGV 98A. Continued monitoring is planned. One measurement at a location north of RGV 98A, showed a heave of 0.14 feet. The pipeline is designed for much larger movements, so this location was scheduled for further follow up. No remedial action is required at this time.

All thermistor sites showed stable thermal regimes during the past year. MLR 1 and MLR 2 now have fully frozen soils down to the bottom of the thermistor string. In many locations, the mainline buried pipe is contributing less heat energy to the soil mass surrounding it, because of lowered throughput. APSC reported that none of the investigations of belowground stability resulted in a recommendation for remedial action.

The integrity program also includes belowground cathodic protection monitoring. Most of the buried section of TAPS is covered by an impressed cathodic protection system. This provides a small voltage to counteract electrolytic effects in the groundwater in the soil surrounding the pipeline, essentially mitigating most external corrosion.

An impressed (or active) corrosion protection system is part of the pipeline integrity plan used by APSC. The system requires little voltage. If voltage is too low, the protective effect of the system can be negated. If voltage is too high other problems can occur, notably disbondment of coating. APSC conducts periodic surveys of buried mainline piping, called close interval surveys to obtain detailed information of the impressed current system and to identify locations where coating problems exist.

Major projects for the 2008 calendar year included performing a close-interval CP survey of nearly 126 miles of the TAPS. Most of this survey (117 miles) took place from PLMP 585.94 to PLMP 799.73. The remaining 8.4 miles of the survey took place in the Atigun Pass re-route. The close interval CP survey involves using surface equipment to assess the electrical potential of the CP system in millivolts (one-thousandth volt). This type of surveying is important because CP problems can be localized.

Other major projects included inspecting (and repairing as needed) all 1,018 test stations on the mainline, and conducting depolarization testing of approximately six miles of various pipe segments that historically showed low potentials. APSC completed installation of active CP systems on most of the last 20 miles of mainline, going into the VMT.

A number of inspections yielded good results for APSC. A 20-mile segment of the mainline (PLMP 780-800) achieved a minimum 93.5% pass rate. Six out of the 54 propane tanks in the southern region did not meet the target potential range, a pass rate of 88.5%. Two out of 779 coupons did not fully meet criteria, a pass rate of 99.7% and four out of the 32 road crossings did not meet MP-166 criteria set by APSC. Two of the crossings are scheduled to be removed and two will be further evaluated. APSC identified nine pipeline milepost locations along the mainline where areas of low potential were evident that either require remediation or have been scheduled for remediation. In some of those locations, only further investigations are being scheduled.

2.1.2.7 APSC Annual Report – Fuel Gas Line (FGL)

The FGL program addresses monitoring and maintenance activities performed on the TAPS FGL. Natural gas for the FGL originates at the Prudhoe Field Fuel Gas facility. It provides fuel gas to Pump Stations 1, 3, and 4. In the late 1990s fuel gas was no longer provided to power facilities at PS 2 due to lower throughput. The FGL is important to the continued functioning of TAPS. Figure 14 shows the FGL compressor skid, located at PS 1, where natural gas is processed prior to being transported to PS 2, PS 3, and PS 4. In the event that the fuel gas line becomes disrupted one of two turbine generators (TGs) located at PS 3 and PS 4 are equipped to operate on diesel fuel.

Figure 14 *FGL compressor skid located at PS 1.*

The 149-mile long pipeline runs from PS 1 to PS 4. It is 10 inches in diameter from Mile 0 to Mile 34 and eight inches from Mile 34 to Mile 149. It is buried over nearly all of its length. Two 1,200-hp compressors at PS 1 compress the gas to approximately 1,000-1,100 pounds per square inch (psi). Due to a lower demand for fuel gas, the compressors that once ran continuously are now run intermittently. The design pressure for the FGL is listed by APSC as 1,335 psi. To protect the permafrost, the buried line is maintained at a temperature of approximately 30°F.

Fuel Gas Line Integrity

APSC identified three areas where FGL integrity work was accomplished during CY08, including CP monitoring at 75 stations, repairing damaged test stations, and investigating dents with gouges near PS 1. Multiple gouges and dents discovered in this location required a sleeve on the affected segment of pipe.

APSC predicted that they would have results from the MFL smart pig, assessing corrosion and mechanical damage in the FGL by the first quarter of CY09. This is the first smart pig run on this pipeline in a decade.

2.1.3 Other APSC Reporting

2.1.3.1 Valdez Marine Terminal

APSC implemented several important projects and repairs this year. Among the two most notable were the turbine revamp and the installation of BTEX-reduction equipment at the BWT facility.

Steam TGs at the VMT generate up to eight megawatts of energy. The generators power all of the terminal's electrical needs. The power generation facilities consist of three steam TGs. During FY09, one of the TGs (the C Turbine) was taken offline for a complete overhaul because of a bearing failure. This overhaul included disassembling the TG, cleaning and inspecting all of its internal parts, inspections and testing.

APSC is completing its BWT facility biological treatment tank replacement project at the VMT during 2009. The area is being updated for the lower volumes of ballast water being produced today. The volumes have decreased because of the reduced number of tankers and because the increased use of double-hull tankers (which produce less "oily" ballast water). The BWT is the primary facility used to separate oil from ballast water and wastewater at the VMT. Previously, the BWT used a three-part process to separate and treat ballast water. The old system used gravity separation tanks that allow for heavy particle separation of water and oil.

The BWT will continue to process run-off at the VMT utilizing a three-part process. The first two phases involve gravity separation and induced gas flotation. The final phase, however, is new. The last phase involves the use of thermal oxidizers to process hydrocarbon, in particular BTEX. The project required a DEC air permit modification, in addition to changes to the Federal National Pollutant Discharge Elimination System (NPDES) wastewater discharge permit. The air permit was modified and approved in June 2008. The NPDES wastewater discharge permit was issued by the U.S. Environmental Protection Agency (EPA) and is scheduled for renewal in June 2009. (The EPA received the reapplication for the permit so it is administratively extended.) Most of the old systems will remain in service at the BWT until the new system has been operating long enough to prove itself.

2.1.3.2 Significant Unplanned Event – January 15, 2009

On January 15, 2009, there was a flaring/venting incident at the PS 1 storage-relief tanks. BP Exploration (Alaska), Inc. (BPXA), was using natural gas to propel a cleaning pig through the 34-inch Eastern Operating Area Transit Line as part of a cleaning/decommissioning process for that line. The following is condensed by SPCO Engineering from the draft and final incident reports. BP and APSC published separate reports, using their individual company methodology. The cleaning pig lodged at an angle, allowing the motive gas to bypass the pig. Gas flowed downstream, around the pig, mixed and entrained with oil. The gas entrained oil flowed to a downstream BP facility, Skid 50, and then to Pump Station 1. The mainline pumps, designed to handle liquids, started to overspeed and automatically shutdown, diverting the gas-entrained oil to storage/relief tanks (T-110 and T-111) at PS 1. A portion of the gas was flared but excess gas was released into the atmosphere through the tank vents. The incident had the potential to shut down TAPS for a significant period of time.

The gas directly discharged from the tank vents is the primary cause for concern with this incident. APSC estimated that the gas cloud that was released from the tanks had a heavier molecular weight than air. Heavier gases tend to hug the ground.

At the time of the incident, the wind was blowing in the general direction from PS 1 to Skid 50. Skid 50 is a facility operated by BPXA as a merging and metering point for transit lines delivering oil from Prudhoe Bay. Skid 50 is located approximately 1,500 feet away from the storage tanks at PS 1. APSC states that the methane detectors at Skid 50 detected levels that peaked at 26% LEL, or Lower Explosive Limit. The Lower Explosive Limit is the minimum concentration that could sustain ignition. Some types of methane detectors are selectively sensitive to methane and some types read abnormally high levels in the presence of other hydrocarbon gases, such as the heavier hydrocarbons discharged from the tanks. SPCO Engineering believes that, while the LEL reading is questionable, it is still useful as a general indicator of the importance of this gas release at PS 1, 1,500 feet away from the detectors.

The wind direction at the time of the release carried the cloud away from nearby sources of ignition. Had the wind been blowing a different direction and toward an ignition source (such as the nearby flare, an idling pickup near the Personnel Living Quarters, or toward the burners on the Northstar line heater) the potential consequences could have been far worse.

Because of the severity of this incident, both APSC and BP conducted independent safety and root cause investigations. Their findings resulted in a number of recommendations. APSC is implementing changes in pump station operations and facility design and BP is implementing changes in pigging and other practices. Examples include modifications to enhance communications between these companies, requirements for inter-company planning on projects and activities that may potentially affect both companies, and improved operational practices, such as pig tracking. In addition, Alyeska implemented some facilities changes. The most important was to prioritize and sanction a project to add foam suppression to the two large storage/relief tanks at PS 1, TK-110 and TK-111. It should be noted that the incident occurred near the start of the work activities needed to decommission old transit pipelines, which had been replaced after the 2006 oil spills. The remainder of the decommissioning activities were completed without serious incident. As a result of the incident, corrective action measures have been implemented by operators on the North Slope and by APSC.

As a result, communications have been improved. When one operator is performing work that may impact another operator or APSC, they will have representatives of the affected company involved in key areas, such as planning, hazards analysis and safety reviews. APSC has installed or is planning to install some plant improvements. BP has modified their pig locating practices. An example of the improved communications was evidenced in the Kuparuk Pipeline Extension de-oiling project. Half of the pipeline was replaced. The abandoned section had to have oil removed from it prior to its decommissioning. The lessee, Kuparuk Transportation Company, engaged APSC representatives early in the planning, hazards-analysis and execution processes, because the oil would eventually reach PS1. However, for this project, the oil had to flow through an oil/gas processing facility that removes nearly all natural gas, and through a 37-mile pipeline to reach PS1.

2.1.4 SPCO TAPS Related Activities

Coordination of the State of Alaska's efforts to conduct oversight of TAPS is accomplished through the SPCO, which co-locates staff from the DNR, DCOM; ADF&G, DEC, DOLWD; and the DPS/SFMO.

2.1.4.1 SPCO Engineering Section

There was a considerable amount of technical/engineering activity on TAPS during the past year including investigation of a major venting incident at PS 1, startup of SR Facilities at PS 4, continued evaluation of low-flow issues, characterization and partial remediation of corrosion found in low-flow piping, continued automation and reduction of operators or demanning certain facilities, and continued optimization of SR facilities, such as improvement in gas supply and control of turbines.

SPCO Overview of TAPS Strategic Reconfiguration

SR was intended to update TAPS for the lower flow rates experienced during today's conditions. The original design basis listed a maximum throughput from the original 2.1 million barrels of oil per day (bopd) and minimum 300,000 bopd. The design basis for SR lists a minimum of 300,000 bopd and a maximum of 1.14 million bopd. APSC has twice utilized impulse, or on-again/off-again pumping techniques to achieve even lower rates. SPCO Engineering believes that in summer, warm fall, or spring conditions, the new equipment can probably achieve some very low rates because it is much more flexible and has a much larger operating band. In low ambient temperatures, however, fluid temperatures make low flow more problematic. This is discussed further in *SPCO Engineering Discussion of TAPS Throughput and Operational Issues* on page 40 of this report.

The major pieces of equipment installed at each location are:

PS 9: three pumps, three Variable-Frequency Drives (VFDs) to throttle the pumps, three electric motors to drive the pumps, and two 2.25- Megawatt (mW) backup diesel generators, a 65 Kilowatt (kW) emergency generator and an electrical connection to the commercial power grid.

PS 3 and PS 4: two 12-mW TGs, three pumps, three VFDs to throttle the pumps, three electric motors to drive the pumps, and one 2.25-mW diesel generator, a 65 kW emergency generator and an electrical connection to the commercial power grid.

PS 1: the addition of two electric-motor drives and VFDs to two booster pumps, three pumps, three electric motor pump drivers, one 12-mW TG, one 5-mW supplementary/backup TG, a 65 kW emergency generator and a backup connection to the

Prudhoe Bay proprietary electrical grid. Table 3 lists the major equipment installed, by pump station.

Table 3. Major Equipment Installations at Pump Stations Subject to SR.

Station	Equipment & Description
PS 9	three pumps three VFDs to throttle the pumps three electric motors to drive the pumps two 2.25 mW backup diesel generators one 65kW emergency generator one electrical connection to the commercial power grid
PS 3 and PS 4	two 12 mW turbine generators three pumps three VFDs (to throttle the pumps) three electric motors to drive the pumps one 2.25 mW diesel generator one 65kW emergency generator
PS 1	two electric-motor drives and VFDs two booster pumps three pumps three electric motor pump drivers one 12 mW turbine generator one 5 mW supplementary/backup turbine generator (under discussion) one 65kW emergency generator one electrical connection to the commercial power grid

More information on the technical upgrades of TAPS by the SR project can be found at the following website: http://alyeska-pipeline.com/sr.html. This webpage also contain 28 hyperlinks to other information on SR, including five fact sheets that provide extensive information on the new equipment.

The SR facilities at PS 9 went online in February 2007. PS 3, in December 2007, but they were taken offline for approximately five weeks to modify the TG air inlets and bypass for better cold-weather operation. They restarted in February 2008. In May 2009, PS 4 SR facilities came online.

After both PS 9 and PS 3 SR facilities had experienced one or more winters of operation, the piping tie-ins to the old legacy equipment were disconnected at both pump stations. This occurred during the 2009 summer shutdowns at both sites. PS 4 SR, which has yet to accumulate a single winter of operational experience, is still connected to its legacy equipment and can revert back to it within minutes if an upset occurs. The PS 4 tie-in to the legacy equipment will be removed during the summer of 2010.

PS 1 Strategic Reconfiguration was originally scheduled to start immediately after PS 4 startup, moving construction crews and equipment from location to location. However, the TAPS Owners elected to defer the remainder of work at PS 1 until a later date.

SPCO Engineering Discussion of TAPS Strategic Reconfiguration
- Update and Reliability

A matter of continuing interest for the State remains the efficacy and reliability of the new SR equipment. The SPCO has monitored this issue and provides the following information, which is condensed from TAPS reports issued by APSC. Table 4 lists shutdowns at Pump Station 3. [*Note that the calendar range begins before the fiscal year covered by this report.*] The information provided in Table 4 was collected after modifications for improved low temperature operation of the turbines were completed and terminated at the end of the FY09.

Table 4. Pump Station 3 Unscheduled Slowdowns or Shutdowns.

Date	Stop	Re-Start	Duration	Event Description
1-Mar-08	2:40	3:03	0:23	Loss of station control panel permissives during pig passage
26-Mar-08	18:02	18:30	0:28	Frequency control on Turbine Generator 3601 (TG-1)
29-Mar-08	13:48	13:54	0:06	Under frequency load shed
29-Mar-08	18:39	19:58	1:19	Under frequency load shed
6-May-08	14:02	14:53	0:51	Mainline unit (MLU) reverse rotation indication; went to idle.
22-May-08	7:37	8:10	0:33	TG Shut down (S/D). Local control net I/O failure.
22-May-08	18:47	19:44	0:57	TG-1 tripped off line. High lube oil temperature.
30-May-08	7:57	8:31	0:34	TG-1 Control Net I/O card failure.
3-Jun-08	15:43	16:00	0:17	Loose connection to ESD button.
9-Jun-08	12:25	13:00	0:35	S/D while accessing Turbine Control Panel.
22-Jun-08	1:18	2:59	1:41	TG-1 tripped.
24-Jun-08	15:00	15:08	0:08	TG-1 and 3602 (TG-2) tripped under frequency load shed
27-Jun-08	9:03	9:39	0:36	Pilot gas valve position indicator.
9-Jul-08	4:31	4:40	0:09	MLU #2 S/D on low lube oil accumulator pressure.
9-Jul-08	12:19	13:06	0:47	TG-2 S/D on high fluid level in wash tank.
10-Jul-08	15:51	17:17	1:26	TG-1 auto tripped off-line during S/D of north end by OCC
13-Aug-08	14:16	14:39	0:23	TG tripped.
20-Aug-08	12:55	13:50	0:55	Running in parallel, both TGs tripped.
20-Aug-08	15:01	15:25	0:24	Second attempt to run TGs in parallel, both tripped again.
6-Sep-08	10:15	12:01	1:46	MLUs S/D low station suction pressure after WAN S/D PS 9.
11-Sep-08	14:29	15:07	0:38	MLU #2 S/D on false high sump alarm. (14:32) ATT radio communication problem. Unrelated simultaneous failures.
17-Sep-08	14:24	14:32	0:08	MLU #1 S/D on low oil pressure.
23-Sep-08	5:02	8:03	3:01	MLU #1 S/D because of air compressor problem.
20-Oct-08	7:42	8:53	1:11	Sequence of failures starting w/ MLU #3 high winding temperature.
2-Nov-08	12:33	13:00	0:27	TG-1 primary generator tripped off-line. All MLUs S/D.
17-Nov-08	13:37	13:43	0:06	Valve opening sequence problem initiated MLU S/D.
9-Dec-08	5:57	6:45	0:48	PS 3 TG-2 tripped. Suspected voltage control problem.
14-Dec-08	21:18	21:42	0:24	TG-1 tripped. No identified cause. Further investigation.
15-Dec-08	6:40	7:03	0:23	TG-2 tripped on high lube oil temperature.
15-Dec-08	18:30	19:00	0:30	TG-1 tripped on low ventilation air flow. (NOTE: plywood intake in use)
28-Feb-09	15:11	16:12	1:01	Maintenance on inverter caused accidental trip.
28-Feb-09	19:32	19:56	0:24	Maintenance inadvertently closed fuel valve to TG-2.
7-Mar-09	14:45	14:51	0:06	Uncommanded S/D signal. Source unknown.
12-Mar-09	12:57	13:09	0:12	MLUs auto S/D after incorrect S1 valve indication.
11-Apr-09	17:14	17:54	0:40	False hi-level signal on sump at PS 3 pump.

Table 4 Continued

Date	Stop	Re-Start	Duration	Event Description
18-Apr-09	17:20	18:01	0:41	TG-2 S/D because of interruption in fuel gas supply.
19-Apr-09	18:52	18:53	0:01	TG-1 & TG-2 in parallel. Transients caused TG-1 to trip.
26-Apr-09	17:16	17:43	0:27	Technician inadvertently closed fuel gas valve for TG-2 instead of TG-1 causing TG-2 to trip and loss of power to the station and S/D of all running MLUs.
24-May-09	14:04	14:31	0:27	TG-2 tripped. Unknown reason. TG-1 used for restart.
3-Jun-09	13:56	15:00	1:04	S/D after Auto Stop Flow initiated at PS 4 during PM.
12-Jun-09	7:21	7:28	0:07	MLU run permissive lost during network troubleshooting.
17-Jun-09	14:16	15:03	0:47	Valves S1, S2 and D1 began transit. Running MLU stopped.
	Total down time for PS 3		**27:51**	
Note: time increments measure in hours:minutes				

To date, few, if any shutdowns have impacted oil throughput. Storage tanks located at points within the system can hold the flow of oil for a period. Flow south of Atigun Pass is not affected by short duration shutdowns at PS 9, and PS 1 can store significant volumes of oil during shutdowns of the northern section, transporting the extra oil once flow commences.

The longest idle time at PS 3 was three hours and one minute; the shortest idle time was one minute.

Table 5 is a similar summary for PS 4 SR facilities. The information in Table 5 begins after start up of PS 4 and terminates at the end of the fiscal year

The following is a similar summary for PS 4 SR facilities:

Table 5. Pump Station 4 Unscheduled Slowdowns or Shutdowns.

Date	Stop	Re-Start	Duration	Event Description
21-May-09	15:06	15:14	0:08	TG-1 was on-line and SR MLUs were on-line, being tested in forward flow configuration. TG-1 tripped due to high generator cooling air temperature, causing loss of SR power to the station and S/D of all running SR MLUs.
28-May-09	13:29	13:45	0:16	Pressure wave from upset at PS 9 resulted in RGV65 pressure rising to 905 psig, which initiated AUTO STOP FLOW, S/D PS4
6-Jun-09	13:19	14:15	0:56	PS 4 primary & secondary PLCs stopped.
		Total	**1:20**	
Note: Time measured in Hours:Minutes.				

Since startup of the SR equipment at PS 9 there have been 50 minor slowdowns, trips, or shutdowns. These shutdowns have resulted in little throughput loss. Many of the issues at PS 9 were not related to the reliability of the SR equipment, but to the loss of commercial grid power. Since then, upgrades to the power feed to PS 9 have resulted in more stable and reliable supply.

Although SR facilities at PS 9, PS 3, and PS 4 have experienced short-duration outages and failures, after two and one-half years, these have resulted in negligible throughput loss.

It is difficult to make comparisons regarding the reliability of pre and post-SR facilities. The original equipment had the benefit of three decades of upgrades and changes. A comparison of the first three years of operations of pre- and post-SR equipment shows that the original facilities experienced longer, more serious downtime events. More information about equipment-caused shutdowns of the TAPS during previous years, involving the legacy equipment, is available online at http://www.APSC-pipe.com/Pipelinefacts/Chronology.html.

SPCO Engineering Discussion of the PS 2 Mainline Re-Route Project

The PS 2 mainline re-route was completed in August 2008 during a scheduled shutdown of TAPS. The re-route bypassed the existing PS 2 legacy pump station by constructing 1,700 linear feet of new 48-inch mainline along the existing PS 2 pad. A minor extension of the pad was required. This project featured the first mainline supports of a new type that rested on the gravel pad and utilized the bearing strength of compacted gravel for support. The supports are adjustable for re-leveling the mainline if required by settling of the pad. As a condition for approval of the project, the SPCO required elevation surveys for the next several years to ensure that the new support design functions adequately.

SPCO Engineering Discussion of Pump Station 3 Demanning

APSC is proceeding with plans to de-man PS 3 and to retire many of its facilities. The “legacy” pump station facilities were placed in cold standby after the oil piping connections between old and new facilities were removed. Figure 15 shows work crews removing the "T" from the legacy piping during the June shutdown at PS 3.

Figure 15. *Work crews during the June shutdown at PS 3.*

Many of the support facilities, including the Personnel Living Quarters, are being shut down, although the fly camps will be kept to provide project housing on an as-needed basis. The control room at PS 3 was de-manned and its functions transferred to the new OCC in Anchorage. The current plans are to have all operational personnel out of this pump station by the end of CY09. Maintenance crews will remain on site most of the time, but they will be housed at PS 4. The fly camps can provide overflow housing for construction and repair crews. Emergency crews will be available at PS 4. APSC is upgrading its security systems. Automation and de-manning of pump stations will continue to be closely monitored by the SPCO.

SPCO Engineering Discussion of the PS 8 Pig Launcher

A "smart pig launcher" was installed at Pump Station 8 (Figure 16) near the Salcha River, approximately 40 miles outside Fairbanks, in summer 2009. The launcher will enable workers to put a "smart pig," a corrosion-detecting device, or other ILI device into the mainline at that point, rather than at PS 4, north of Atigun Pass. This will reduce the travel distance for the ILI device from approximately 600 miles to approximately 400 miles. This modification was performed during a regular semi-annual maintenance shutdown. APSC has stated that the new launcher may not be used for all ILI runs and is not planned for it to be utilized for maintenance pigging. It will be kept as a contingency option if a pig cannot provide an acceptable "run" from PS 4 to the VMT.

Figure 16. *The pig launcher at PS 8.*

SPCO Engineering Discussion of TAPS Throughput and Operational Issues

The average TAPS daily throughput in 2008 was 703,551 barrels. This represents 35% of the average daily throughput of 2,033,082 barrels per day for the highest throughput year, 1988. As North Slope crude oil production continues to decline, the TAPS operation will be affected by many factors including low flow, crude oil composition, and temperature. These changes have the potential to impact instrumentation, pumps, and other critical equipment.

Reduction in TAPS throughput causes a reduction of fluid temperatures. The transit time is increased and consequently oil has a longer time to cool during its travel south. Lower oil temperatures will result in new operational challenges. During the first decade of pipeline operation, oil flowing out of PS 1 averaged about 110°F. Depending upon ambient temperatures along the route on a typical winter day, oil temperatures dropped to 70°F by the time it reached Fairbanks and 60°F by the terminus at the VMT. The refinery provides a significant boost to the temperature of the oil. Unlike many refineries, the Flint Hills facility returns product to its supply pipeline. It uses only certain components and returns the rest at higher temperatures.

Today, the temperatures exiting PS 1 are largely unchanged. However, on a typical winter day fluid temperatures may drop down to 40-45°F at the coldest section of the pipeline, PS 7 to North Pole. North Pole is the location at which the returned fluid from the refinery is combined back into the mainline flow and boosts oil temperature.

This boost effect increases as flow in TAPS decreases. Similarly, the heat from Flint Hills has proved even more important during low-flow events, such as loading restrictions at the VMT.

TAPS has experienced incidents that provide a glimpse of the problems anticipated for the future. In November 2006, low output from Prudhoe Bay caused fluid temperatures in TAPS to drop to about 40°F. Although no major operational problems ensued, the low temperatures caused concern and operations were closely monitored. APSC utilized intermittent pumping for the first time.

In December 2008, similar temperatures were reached because of sustained high winds at the VMT that disrupted tanker loading. The North Slope producers were placed on prorated production. For the second time, APSC used intermittent pumping. Again, no major problems occurred but low fluid temperatures caused concerns.

APSC initiated a major study to evaluate specific characteristics of North Slope crude oil and how lowered throughput, changing crude oil composition, and temperatures might affect the operation of TAPS. The SPCO will closely monitor the progress of these studies, specifically with respect to potential mitigation measures. Specific study objectives include:

1. Ice Studies - At fluid temperature of 28°F or below, saline ice potentially can form in TAPS. This has wide-ranging implications for TAPS operations, for North Slope facilities, and for storage at the VMT and for loading tankers. In addition, more problems may occur under an adjunct to low-flow scenarios, cold or cool restart. These are the terms for restart after flow has been stopped for extended periods, resulting in a cooling of the oil.
2. Bulk Paraffin and Pigging - As fluid temperatures in TAPS decrease, greater amounts of paraffins (a type of wax) and asphaltenes (dense petroleum) will begin to drop out of solution. Wax buildup has caused APSC to increase its maintenance pigging frequency. Figure 17 illustrates one type of maintenance pig. It was also part of their decision to use MFL smart pigs instead of UT smart pigs.

Figure 17. *Maintenance Pig used to clean the pipeline.*

3. Viscosity and Gelling - To date, TAPS has never had to transport oil at fluid temperatures below approximately 38°F. Any upsets or other low-flow situations during cold weather may create unprecedented situations for TAPS. Wax and asphaltenes will precipitate out of solution, coat the internal surfaces of pipe components and instrumentation, as well as the mainline, and pump station piping. At colder temperatures, wax will also contribute to the transformation of oil into a gel. This is important because a gelled fluid is a thixotropic substance. It does not flow as easily or predictably as a typical crude oil, which is a Newtonian fluid. At 28°F, the water in TAPS, which can constitute up to 0.35% of the net volume, will begin to freeze into saline ice that could damage pumps, clog screens, and disable instrumentation. The technical difficulties of pumping TAPS-quality crude oil under these conditions are not fully understood, and APSC is evaluating the problems as part of their series of studies.

Pipeline Vibrations

Recently, two types of piping experienced vibrations that prompted engineering evaluations. The first area is on the south side of the Brooks Range, near Atigun Pass. An aboveground section of pipeline vibrates and the amplitude varies with time and conditions. The second is the piping outside the new SR pump modules at PS 3 and PS 9.

The pipeline vibration issues at Atigun are similar to those experienced at Thompson Pass over a decade ago. The same mechanism is operating at both sites. There are three major passes in the TAPS ROW corridor, Atigun, Isabel and Thompson. Ten years ago at Thompson Pass lower throughput caused vibrations that were felt as far away as Valdez. This problem was remediated by supplying backpressure at the bottom of the slope, which caused the liquid level in the pipe to rise and the elevation drop in the slackline to be reduced. The vibrations at Atigun are of lower amplitude and are consequently less severe than the vibrations were at Thompson Pass. It should be noted that Isabel has a smaller elevation change and unusual vibrations have not been reported at that site. APSC has installed solar powered data loggers at the base of Atigun Pass, just south of PLMP 169 (Figure 18).

Figure 18. *TAPS PLMP 169 near Atigun Pass. The solar panel provides power to vibration sensors and data loggers.*

APSC instrumented four locations at the area of concern at Atigun Pas and came to the preliminary conclusion that the vibrations did not present a threat within the near or intermediate future. Vibrations create fatigue in the welds, parent metal of the pipeline, and typically act in a mathematically predictable manner, based upon the fatigue cycles. Based upon the data collected, APSC is not recommending action in the near future. It should be noted that the vibrations at Atigun are likely caused by the lowered throughput creating a longer section of slackline in the area, and hence a longer drop for fluids as they crest the top of the pass and cascade downhill to a liquid-filled section of line. Continued changes in the flow rates of TAPS may result in greater or less vibration, so this topic is being followed closely.

The second type of pipe vibrations involved vibrations in the piping outside the new pump modules installed under SR. Initially, many assumed that this vibration so close to the pump must be caused by the machinery. An analysis has shown that the vibrations are generated within the supply and return piping to the pumps. This is called flow-induced vibration. APSC contracted with an engineering firm that specializes in vibration problems, and they recommended upgrades to reduce the flexibility of the piping supports. These upgrades were made at PS 9, which displayed the greatest vibrations, and PS 3. They also recommended adding minor supports to branch connections and instrumentation located within the pump modules. Testing after PS 4 SR startup indicated that vibrations at that location were within nominal values. Therefore, no work is planned at PS 4. Figure 19 shows the bracing for PS 3 being fabricated, Figure 20 shows the first brace being installed on one of the pump modules at PS 3, and Figure 21 shows the underside of the pump module after the bracing was installed.

Figure 19. *A brace being assembled.*

Figure 20. *First brace being installed at PS 3.*

Figure 21. *Bracing installed under pump module at PS 3.*

Figure 22 illustrates the stiffeners and pipe clamps that were installed at PS 9, new supports were installed on both sides of the building.

Figure 22. *The pipe configuration causing vibration at PS 9.*

Revised Maintenance Agreement

Although the FGL shares similar maintenance concerns with the TAPS mainline, it has its own unique maintenance concerns. During the 1990s, the JPO and APSC executed a maintenance agreement for the FGL. The JPO approved amendments to this agreement in 2007. The agreement calls for a limit on the curvature of the pipeline, a "blue-board" survey that looks for and remediates sections of pipe that have the geothermal insulation boards showing, and new methods of LIDAR surveys and inertial geopig surveys that may be able to establish the burial depths of the pipeline along the entire FGL route with improved accuracy.

In 2008, a LIDAR ground elevation survey was conducted and an MFL corrosion smart pig was run. The smart pig was integrated with a geopig, an inertial survey tool that can locate the pipeline along three dimensions.

SPCO Engineering reports that during 2009 and 2010, APSC will attempt to integrate the data from the LIDAR survey and the data from the inertial ILI device, the geopig. One database contains surface profile information. Another database carries information on the centerline horizontal and vertical locations. The difference between these values at any point will determine burial depth. Prior to this technology being used, the best data on depth of burial came from monitoring rods that were located at points of interest a few thousand feet apart giving burial depths for only a small portion of the pipeline. This new quantitative methodology can be used establish more accurate burial depth along the entire route.

PS 1 Producer Pipelines
Note that these pipelines are also covered in the respective State pipeline section. Several pipelines from processing facilities across the North Slope converge at PS 1. All of these, except Oil Transit Line (OTL) 501 from Prudhoe Bay and the Lisburne Pipeline, are on state AS38.35 right-of-way leases and subject to monitoring by the SPCO. The transit lines from Prudhoe, which were involved in two major spills in 2006, are part of the oil field leases. Because of these spills and other reasons, the sections of the producer pipelines within the fenced boundaries of PS 1 have garnered attention. The pig receivers for these pipelines are outside of the boundaries of the pump station. Two of these pipelines are buried or encased in concrete and are difficult to inspect using direct assessment methods. These are the single transit line from Skid 50 (Figure 23) and the Kuparuk pipeline. Both pipeline operators have announced plans to replace the sections at PS 1.

Figure 23. *Skid 50, near Pump Station 1.*

2.1.4.2 SPCO Compliance Section

The SPCO monitors the Lessee's and Operator's compliance with obligations established under the TAPS Right-of-Way Lease. In this capacity, the SPCO Compliance Section ensures that representatives of the State of Alaska have access to the ROW, pipeline, and related facilities. This access includes the ability to inspect documents pertaining to surveillances, quality assurance and integrity plans that APSC and the other lessees are obligated to maintain (and report on).

SPCO Compliance Section staff conducted seven inspection trips of TAPS in FY09. These trips generated 37 signed and completed surveillances (Appendix I). The trips included participation in the Phelan Creek oil spill exercise, travels along TAPS with the ADF&G representative and representatives from APSC trips with the DOLWD safety inspector, and observations during both the August 2008 and the June 2009 planned maintenance shutdowns.

Pump Station 2 Re-route Project

Two Compliance Section staff members monitored the reroute of the mainline pipe that put into place a 1,700-foot, aboveground pipeline segment that bypassed the PS 2 manifold building and other legacy equipment. The final tie-in for the re-route project occurred during the August 16, 2008 shutdown. Part of the new pipe segment had machined anomalies (Figure 12), both internal and external, which would aid in pig calibration. Work to cut the mainline and connect it to the new section of pipe at the south end went smoothly. Figure 24 shows the automated beveling machine that was used to cut the pipe before welding. PHMSA issued an approval to sleeve a weld on out-of-round pipe.

Figure 24. *Automated Beveling Machine at the PS 2 Re-route Project.*

Pipeline Shutdown – 8/16/2008

During the shutdown, Compliance Section staff joined a BLM staff member monitoring activities at PS 3. Shutdown activities at PS 3 included cutovers to the Safety Integrity Pressure Protection System (SIPPS) control, strainer removal, and gas building fire system commissioning. Gas building activities were complicated at PS 3, by the reluctance of a gas blow down valve 310R to function. A comparable valve was removed from PS 4 for installation in PS 3. SPCO staff members observed some communication difficulties during the transition of control from the pump station to the OCC. During the commissioning of the fire system, issues resulted as part of the installation of the supervisory control and data acquisition (SCADA) system. As a result, the SCADA system was bypassed, and the legacy fire system activated, until the issue could be resolved.

Pump Station 3 SR Turbine Generator 1 – Burner Can Assemblies

During a planned shutdown in August 2008, JPO staff noted that the TG-1 burner cans assemblies (Figure 25) were laid out on a table in the module. Prior to shutdown, TG-1 shut down and would not restart. Evidence of natural gas liquids (NGLs) were found in the burner assemblies. It was determined that an upset at PS 1 introduced unprocessed NGLs into the fuel gas line and then into the turbine generator's burner assemblies. Replacement assemblies were installed. The original, damaged, assemblies were sent out for refurbishing.

Figure 25. *Burner Can Assembly Removed from TG 1 at PS 3 on 8/18/2008.*

Pipeline Shutdown – 6/20/2009

The SPCO Compliance Section traveled to PS 3 for a scheduled shutdown of TAPS that began June 20 and ended June 21 of 2009. This trip generated several surveillances and a field report describing the basics of the projects initiated at PS 3 during the June shutdown.

Surveillances completed during this trip addressed health and safety, operations, and sanitation and waste disposal issues. The field report generated by this trip describes the four projects completed during the shutdown. These projects included disconnecting the legacy pump equipment and associated piping, replacing a mainline valve (M2), installing a hydraulic ram override in the gas building, and performing maintenance to the LEFM.

The SPCO Compliance Section noted that all four projects were conducted without any major complications and completed ahead of schedule. .

Other Field Trips - Inter-Agency

During fiscal year 2009, Compliance Section staff joined other agencies in the field. Along TAPS, the Compliance Section traveled with the liaison from ADF&G and APSC staff on river inspections, several times including trips on July 8, 2008 from Fairbanks to Pump Station 5 and on June 17, 2009 from PLMP 679.9 to 795.3. Figure 26 shows the signage at the LWC on the North Fork of Aggie Creek, which the ADF&G Liaison inspected while accompanied by a member of the Compliance Section. Compliance Section staff joined the DOLWD on safety inspection trips to pipeline facilities and project sites on November 13, 2008 and April 1, 2009. Compliance Section staff also participated in the Phelan Creek oil spill drill on September 11, 2008.

Figure 26. *July 8, 2008 TAPS stream crossing trip with ADF&G Liaison.*

2.1.4.3 SPCO Right-of-Way and Permits Section

Lease Amendments, Permits, and other Authorizations

During FY09, the SPCO ROW and Permits Section completed 32 authorizations in support of TAPS maintenance and repair activities. This included 11 authorizations or amendments for temporary water use, two material sale contracts, 17 land use permits, one ROW lease amendment, and one authorization to operate equipment outside of the ROW per Lease Stipulation 2.9.1. These authorizations are summarized in Appendix D, Authorizations, Rights-of-Way, and Permits Issued by Quarter in FY09.

Mineral Material Site Surveillance

During FY09, the SPCO ROW Section conducted inspections and completed surveillance reports for twenty of the twenty-nine operating material sale sites on state land along TAPS (Surveillance Report Numbers 08-TAPS-S-088 through 08-TAPS-S-117). The sites were inspected between July and September 2008 to determine compliance with the material sale contract, mining and reclamation plans, and TAPS Lease Stipulation 2.6, Material Sites. The material sites were found to be generally clean, well-maintained and met requirements. A minor unsatisfactory observation was reported at OMS 14-0. Also, a minor unsatisfactory observation was reported OMS 41-3. Both unsatisfactory observations pertained to one attribute regarding side slopes on the rock face, which appeared to be steeper than provided in the mining plan. These unsatisfactory conditions were later addressed by APSC. Figures 27 and 28 show the conditions of OMS 3-1.1 when ROW Section staff inspected the site during the summer of 2009.

Figure 27. *OMS 3-1.1, accessed by TAPS Access Road 2-APL-1 from Dayville Road MP 1.03.*

Figure 28. *OMS 3-1.1 near PLMP 795.2.*

Agreement Amended

In a 2004 agreement entered into between the State of Alaska and Koch Industries, Inc., Flint Hills Resources, LLC, Koch Alaska Pipeline Company, LLC, Flint Hills was required to maintain financial sureties to protect the public from any damages Koch might be liable for arising from TAPS operation, maintenance and termination activities. Flint Hills requested that the guaranty be modified which was executed on October 2, 2008.

2.1.4.4 Alaska Department of Labor and Workforce Development

2.1.4.4.1 Safety Inspections

The DOLWD Safety Liaison (Figure 29) conducted 33 annual safety inspections of APSC facilities for compliance with lease and grant stipulation 1.20, Health and Safety. Federal Occupational Safety and Health Standards (29 CFR 1910 and 29 CFR 1926) are used for an inspection standard. The facilities include each pump station, the Response Bases, the drag reducing agent injection site at PLMP 238, the Fairbanks area shops and storage facilities, and the VMT.

In addition to annual inspections, the DOLWD Safety Liaison conducted eight work site inspections for compliance with lease and grant stipulation 1.20, Health and Safety. The inspection standard for a work site is the same as annual inspections, with more emphasis on safety programs and procedures. Work sites included:

- PS 3 post SR construction activities.
- PS 4 SR energy isolation and permit confined space entry procedures and four work site safety inspections.
- PS 8 removal of the manifold building and installation of the new pig launcher facility.
- Pipeline integrity investigations at PLMP 648 and PLMP 653.

A total of 19 safety violations were identified in FY09. These violations were minor in nature and have been corrected.

The Safety Liaison escorts new SPCO staff on TAPS orientation trips (Figure 29).

Figure 29. *DOLWD Safety Liaison (on left) escorting new SPCO staff on an orientation tour of the TAPS.*

Injuries
APSC reported 13 recordable injuries during FY09. A "Recordable Injury" is any injury requiring medical treatment. Of the 13 Recordable Injuries, five were Days-Away-From-Work-Cases.

Accident Rates
APSC injury rates are below the Bureau of Labor Statistics national average for North American Industry Classification System code 486110, Crude Oil Pipeline Transportation. These rates are maintained by calendar year.

As of December 31, 2008, the National Recordable Injury rate for Crude Oil Pipelines was 2.0 injuries per 200,000 hours worked. APSC had a Recordable Injury rate of 0.26 injuries per 200,000 hours worked, their contractors had a recordable rate of 0.59 injuries per 200,000 hours worked, and the combined APSC/Contractor rate was 0.54 injuries per 200,000 hours worked.

The National Days-Away-From-Work and Restricted-Work rate for Crude Oil Pipelines was 0.9 injuries per 200,000 hours worked. APSC had a rate of 0.0 injuries per 200,000 hours, their contractors had a rate of 0.23 injuries per 200,000 hours worked, and the combined APSC/Contractor rate was 0.17 injuries per 200,000 hours worked.

APSC is on track to maintain this record for 2009.

2.1.4.4.2 Electrical Inspections

This past fiscal year there have been six major developments in electrical projects and innumerable small projects on the TAPS.

- Line Wide. New Control, Automation, Communications, and Security systems. Much of this is still ongoing, but APSC was able to close down the Valdez OCC and transfer control to the new Anchorage OCC and implemented a new Anchorage based Security Operation Control Center.
- PS 1. SR Project has been delayed.
- PS 3. F-730 Project is the designation given for a combination of projects that were an outcome from, and a result of, the SR project and the beginning of the dismantling of the old legacy buildings and equipment that are no longer needed.
- PS 4. SR Project completion and forward flow of oil.
- PS 8. Removal of the old Manifold Building and installation of the new pig launcher facility (FY10).
- VMT. New Power Distribution Center with electrical and control systems for the new enlarged and remodeled Valdez Marine Terminal BWT facility.

The DOLWD Electrical Inspector also tracks code violations, issues Notices of Violation, and verifies the corrections with follow up inspections. The Electrical Inspector checks that electricians and contractors are licensed. The inspector physically inspects electrical work during random on-site inspections to verify that the code requirements are being met. The Electrical Inspector focuses on timely verification of code violation abatements. In FY09, the Electrical Inspector performed 64 inspections, issued three notices of violation (all have been corrected) and reviewed 23 Certificates of Fitness. The Inspector also provides code interpretations, both verbal and written, and JPO engineering staff consultations.

<u>2.1.4.5 State Fire Marshal's Office - Inspections & Reviews</u>

The Fire Safety Specialist, under the authority of the State Fire Marshal and pursuant to the provisions and stipulations of the TAPS Grant and Lease, conducts fire and building inspections, building construction inspections, fire life safety inspections, building plan reviews, fire system plan reviews, and other related activities. As noted in last year's annual report the Fire Safety Specialist functions have recently increased to cover non-TAPS jurisdictional pipelines located in Southcentral Alaska and on the North Slope.

TAPS Fire Inspections

The annual TAPS inspection was conducted in May of FY09 and covered the entire 800-mile length of the pipeline from PS 1 to the VMT. The inspection covered a number of TAPS facilities, including Ship Escort Response Vessel System, Galbraith Airport, Prospect Airport, Fairbanks Response Base, North Pole Metering, and Petro Star Metering. Altogether 453 buildings were inspected and 67 hazards were identified for corrective action. Though the number of items requiring corrective action was greater in CY08 from CY07, this year's corrections were more minor in nature and most were corrected on the spot. The TAPS inspections took two and one-half weeks to complete.

Plan Reviews

For FY09 APSC submitted 27 plan reviews, one of which is still pending and has been put on hold by the project team.

Significant issues (TAPS)

There were two significant incidents involving the TAPS that were addressed in FY09. On January 15, 2009, BPXA was pigging its eastern area transit line, for decommissioning, when an unexpected gas/oil surge tripped the turbines at PS 1, diverting a mixture of gas and oil to the station's storage tanks. The field gas was vented from tanks creating an explosive/flammable vapor cloud. The Division of Fire and Life Safety (State Fire Marshal's Office) worked with other agencies of the JPO to request that a foam suppression system be installed in the storage tanks at PS 1. APSC has committed to complete engineering and design of the system by the end of 2009/early 2010. Installation of a suppression system will occur in 2011 and 2012. (Further discussion of this event is included in section 2.1.3.2 of this report.)

The second incident involved the eagle quantum fire panels located in the Turbine Generator Modules at PS 3 and PS 4. A notice of Correction (Non-Compliance) was issued to APSC, directed at Siemens (the manufacturer of the turbine generators) to correct the problem. The engineering solution for making the correction has been received by APSC, and work is to begin at PS 4 in the next fiscal year.

Miscellaneous Activities

The Taps Fire Safety Specialist accompanied the VMT Fire Brigade to annual training at Texas A&M in the Fall of FY09. He subsequently recommended to APSC management that further training of this nature should be considered for the company's employees. Periodic visits were made to the VMT to observe hydrostatic testing, fire alarm testing, storage tank drawdowns, and foam spider inspections. The Fire Marshal Liaison also attended a two-week training course at the National Fire Academy, Emmetsburg, MD.

Other activities conducted in CY08 included providing written and verbal Code interpretations[5], documenting and investigating employee concerns and complaints for TAPS (as they pertain to fire systems and Life Safety Issues), supporting other agencies under the grant and lease agreements, participating in and observing activities of the APSC Fire Brigade and other fire crew activities, and tracking and documenting annual inspections testing and maintenance of fire suppression and alarm systems for TAPS facilities.

Building & Fire Inspections

The Fire Safety Specialist performed 412 Building and Fire inspections for TAPS facilities this past year.

2.1.4.6 Alaska Department of Environmental Conservation

2.1.4.6.1 Oil Discharge Prevention and Contingency Planning (C-Plan)

C-Plans are required by State pollution prevention statutes and regulations, the Lease and the Grant. Variations of spill prevention and response plans are also required by multiple federal agencies, including PHMSA, U.S. Coast Guard (USCG), and the EPA. DEC staff at the SPCO review and enforce compliance with C-Plans for the TAPS Pipeline and the VMT as required by State law, and in so doing, support the SPCO in fulfilling Lease Stipulation 2.14, Contingency Plans. State C-Plans are required to have five parts: Response Plan, Prevention Plan, Supplemental Information, Best Available Technology Analysis, and Response Planning Standard (RPS) Calculation. Each portion of a C-Plan is reviewed for compliance with State regulations found in 18 AAC 75, Article 4. Once approved, C-Plans must be renewed and undergo a full review every five years. During the five-year approval period, the operator may submit both major and routine amendments for DEC's review and approval. DEC conducts its review of the TAPS Pipeline and VMT C-Plans in coordination with BLM and with input from other JPO agencies, including EPA, DNR, ADF&G, and PHMSA. Oversight of compliance with C-Plans includes review of the plan application as well as conducting and evaluating spill response exercises, and conducting audits and inspections.

TAPS Pipeline C-Plan

On a regular basis, the TAPS Response Planning Group composed of APSC, DEC, and JPO personnel meet to facilitate on-going oversight of compliance with the C-Plan and with State statutes and regulations. The purpose of these meetings is to coordinate C-Plan amendments, drills and exercises, inspections, audits and emerging issues among the various oversight agencies and APSC.

The most recent renewal of the TAPS Pipeline C-Plan was approved on November 30, 2006. In FY09, there was one major amendment to the TAPS Pipeline C-Plan. APSC, as part of implementation of the SR Project, transitioned PS 3 to an automated facility, and its Initial Response Team personnel were relocated to the Galbraith Response Base at PS 4. DEC and BLM had approved the relocation of response resources in concept during

[5] Based on AS 18.70, and State Adopted National Fire Protection Association Standards, the 2006 International Fire Code, International Building Code and International Mechanical Codes.

the 2006 TAPS C-Plan renewal; but a major amendment review, including a public comment period, was initiated in the first quarter of FY09. DEC approved the amendment with conditions and coordinated with JPO to ensure the Management of Change process was in place to ensure a smooth transition while maintaining response readiness. Ten Response Planning Group meetings were held in FY09.

At the beginning of FY09, a formal hearing concerning a challenge to the TAPS Pipeline C-Plan approval from 2006 was concluded, and final written arguments were submitted to an Administrative Hearing Officer. To date, a proposed decision has not been issued, and the administrative hearing process thus continues into FY10.

VMT C-Plan

On a quarterly basis, the VMT C-Plan Coordination Group meets for purposes similar to those of the TAPS Response Planning Group: on-going oversight and coordination of activities, compliance, emerging issues, and scheduling for drills, exercises, and inspections. DEC and BLM staff always participate in these meetings, and as available, USCG personnel join in as additional agency oversight and participation. For response to a spill origination at the VMT, the USCG would fill the role of Federal On-Scene Coordinator (FOSC) and the USCG has specific jurisdictional oversight of certain VMT activities. In addition, Prince William Sound Regional Citizens' Advisory Council (PWS RCAC) is a member of the Coordination Group and participates regularly in meetings and review of the VMT C-Plan.

The VMT C-Plan was renewed at the end of FY08. In FY09, four routine amendments to the VMT C-Plan were reviewed and approved. Another four amendments were submitted for review in FY09, although their review and approval decisions were not complete until FY10.

In the VMT C-Plan, APSC included an initiative to re-write the RPS Scenario, known as Scenario 5. The RPS Scenario in the VMT C-Plan depicts the resources, schedule, strategies, and tactics that APSC could use to respond to a discharge of oil to the land and waters of the State of Alaska. Two workshops involving the Coordination Group and other subject matter experts (SMEs) from within the agencies and APSC were convened to consider response alternatives for Scenario 5. APSC has recently determined that it would be better to re-write Scenario 5 in the context of the next C-Plan renewal. Therefore, efforts will be focused on submitting a revised RPS scenario for the 2013 renewal application.

Other Activities

Early in FY09, DEC and the JPO became aware of leaking catch basins and manholes in the secondary containment systems at the VMT. Secondary containment is required by State regulation in 18 AAC 75.75 and by Stipulation 3.11, Containment of Oil Spills, in the Lease and Grant. DEC and BLM both issued enforcement actions requiring corrective plans and action for the faulty components of the secondary containment systems. APSC undertook efforts to repair catch basin, sump, and manhole penetrations in secondary containment, with recognition that on-going assessment and evaluation of corrective measures was warranted. APSC conducted Reliability Centered Maintenance

(RCM) analysis to determine the causal factors contributing to the identified failure, and DEC, BLM and PWS RCAC were invited to attend the analysis. A final RCM report was issued in late FY09 and various maintenance actions were identified to prevent similar failures at the VMT in the future. DEC's Notice of Violation is still active pending completion of final repairs and agreement for future maintenance, inspection schedules, and plans.

In December 2008 and January 2009, an extended period of adverse weather in Port Valdez and resulting impacts to tanker traffic and the ability to off-load oil from the VMT led to very high crude oil inventories at the terminal. DEC and other agencies have long worked with APSC to identify mitigating measures to reduce risk associated with forecasted adverse weather and to facilitate decision making when adverse weather and high inventories require difficult operational calls. During this event, DEC personnel were on call 24-hours a day to ensure loading decisions and measures to enhance the safety of loading crude oil into tankers were as strong as possible. APSC mitigated the risks to the VMT and the tankers by cycling operations as much as cold weather restrictions would allow. (See the discussion on Cold Restart). As a follow-up, DEC held an Adverse Weather loading exercise with APSC in March that focused on safely loading tankers. DEC staff continues to work closely with APSC and the shipping companies to improve on adverse weather loading and high inventory mitigation measures.

Drills and Inspections

One of the oversight authorities DEC brings to the SPCO is the regulatory authority to require C-Plan holders to conduct oil spill response exercises.[6] Specific requirements for exercises have been incorporated into the TAPS Pipeline and VMT C-Plans as well, and are enforceable through the Lease and Grant. During FY09, DEC staff participated in 14 major spill response exercises at the TAPS Pipeline and VMT. There are many types of spill response exercises, including local tabletop exercises, local field deployment exercises, pipeline reconnaissance exercises, local training exercises, combined resource field deployment exercises (multiple response bases responding to a pipeline scenario), terminal field deployment exercises, and Incident Management Team (IMT) exercises. Table 6 provides a summary of major oil discharge response exercises conducted in FY09. Each facility holds at least one IMT exercise per year. At these exercises, DEC's response team is led by one of the agency's regional State On-Scene Coordinators (SOSC). The SOSC, FOSC, and Incident Commander and their respective staff form the Unified Command. Jointly, the Unified Command is responsible to execute an effective response. Figure 30 shows an APSC Oil Spill Response truck deployed during an exercise.

[6] See 18 AAC 75.485, *Discharge exercises*.

Figure 30. *APSC Oil Spill Response truck deployed for an exercise.*

Table 6. Major Oil Discharge Response Exercises, FY09.

Date	**Facility**	**Exercise Type**	**Location**	**DEC/JPO Participation**
August 26, 2008	TAPS Pipeline	Combined Resource Field Deployment	Chandalar Lake	Yes
September 11, 2008	TAPS Pipeline	IMT and Combined Resource Field Deployment	Phelan Creek and Fairbanks Emergency Operations Center	Yes (including SOSC, FOSC, SOSC, and BLM field and compliance teams)
October 28, 2008	VMT	IMT Tabletop for RPS Scenario (203,000 barrel spill)	VMT, Valdez Emergency Operations Center	YES
November 20, 2008	TAPS Pipeline	Unannounced, Joint JPO/DEC Initiated Fairbanks Initial Response Team Callout Exercise	Fairbanks Response Base at Nordale Yard	YES
March 19, 2009	TAPS Pipeline	Unannounced, Joint JPO/DEC Initiated Fairbanks Initial Response Team Callout Exercise	Fairbanks Response Base at Nordale Yard; Fairbanks Fab Shop at DIF	YES
March 19, 2009	TAPS Pipeline	Unannounced, Joint JPO/DEC Initiated Glennallen Response Base Initial Response Team Callout Exercise	Glennallen Response Base, Glennallen, AK	YES
June 10, 2009	TAPS Pipeline	TAPS Airboat Operator Field Training Exercise	Tanana River	YES
June 11, 2009	TAPS Pipeline	TAPS Local Fairbanks Response Base Field Deployment Exercise	Chatanika River	YES
June 25, 2009	VMT	VMT Field Deployment Exercise	Valdez Marine Terminal, Port Valdez	YES

DEC also has the statutory and regulatory authority to conduct inspections for compliance with C-Plan commitments and prevention requirements as well as to determine response readiness. Part of overseeing drills and exercises involves assessment of readiness and training for response. In addition, DEC conducts inspections based on priorities established in cooperation with the JPO Oil Spill Team. During FY09, DEC staff conducted five field inspections, summarized in Table 7.

Table 7. DEC Field Inspections, FY09.

Date	Facility	Focus	Location	DEC participants
September 30, 2008	VMT	Crude Oil Storage Tank 7	VMT, East Tank Farm	Bill Haese, Roger Burleigh
October 27, 2008	VMT	Secondary Containment Repairs	VMT, East Tank Farm	Becky Spiegel, Bill Haese
February 12 – 13, 2009	Pump Station 1 and BP Skid 50	Site visit to learn circumstances of BP Pigging Incident that led to PS1 vapor event	Pump Station 1; BP Skid 50	Bill Haese, Gary Evans, Graham Wood
March 20, 2009	TAPS Pipeline	45' and 32' Response Trailer Inventory Modifications	Glennallen Response Base, Glennallen, AK	Bill Haese
April 28, 2009	VMT	BWT Facility Walk Through	VMT, Valdez, AK	Becky Spiegel, Bill Haese

2.1.4.6.2 Solid Waste Disposal Sites on TAPS[7]

The DEC Division of Environmental Health governs safe drinking water, food and sanitary practices. DEC Environmental Health involvement on TAPS includes permitting for Solid Waste, Pesticides, Drinking Water, and Food Service activities and covers the entire TAPS facility, including pump stations, response bases, support facilities, work pads, and temporary camps.

There are three DEC-permitted solid waste disposal (SWD) sites associated with TAPS: SWD 38-1, SWD 117-1B, and SWD 124-1. Surveillance was conducted of all three sites during FY09. At SWD 38-1, a small amount of remnant ash was observed that had not been properly disposed of after an open burn. The APSC Solid Waste SME was notified and the local Pipeline Civil and Maintenance (P&CM) Coordinator was tasked to properly dispose of the ash in accordance with DEC regulations and permit requirements. No problems or permit issues were noted at the remaining two solid waste sites, which were found to be free of litter and properly closed for the season.

During DEC's permit renewal process for these three sites, APSC identified the need for discreet locations to conduct open burns. Open burning is regulated by the DEC Air Quality Division, and disposal of the residual ash is regulated by the Solid Waste Program. Open burning on lands owned by the state and federal government normally requires temporary use permits which are not issued by DEC. At these locations, typically in gravel pits, it is challenging for APSC to obtain the multiple permits and authorizations needed for compliance with DEC and the Lease and Grant. DEC worked closely with APSC to ensure the renewed SWD permits incorporated provisions to allow for open burning and ash disposal at these sites. APSC incorporated site-specific operational requirements for each permitted SWD site into APSC environmental

[7] Oversight Authority: 18 AAC 60 and Lease and Grant Stipulations 2.2.6.2 and 4.1

procedures. As such, these operational requirements are now enforceable through the Lease and Grant as well as through the permit compliance authority of DEC.

During FY09, APSC proposed to open burn as much as 150 cubic yards of waste wood from SR project activities at Pump Stations 3 and 4 at SWD 117-1B. The material consisted of dunnage and shipping containers. This proposed open burn was for a quantity significantly greater than typically encountered by either DEC or the JPO, and it was determined to be a significant project by the BLM AO. At the request of the DEC Liaison, APSC developed a disposal plan for the activity that was successfully coordinated with the SPC and AO, the DEC Air Quality Division and Solid Waste Program, and the APSC Environmental SMEs for air and solid waste.

During FY09, APSC completed a project to repair the original final cap for a historic waste disposal facility at SWD 124-1. SWD 124-1 was the disposal site for TAPS construction activities in the Happy Valley Camp area until 1976 when it was closed. The site cover installed at that time had since deteriorated to expose previously discarded waste materials. In 2007, APSC developed a project to recover and re-vegetate the site. The SPCO lands and permits team requested policy guidance from DEC concerning regulatory requirements and the APSC project plan. The SPCO and DEC worked with the Environmental Health Solid Waste Program to ensure the new cover would meet current DEC solid waste requirements. The two offices also worked with the DEC Contaminated Sites Program to ascertain whether additional site characterization would be needed. Following coordination, the SPCO issued Land Use Permit, LAS 26494 on July 30, 2008, and recover project was completed. As a result of the interagency coordination and collaboration with APSC, the project and the APSC Solid Waste SME were nominated for the 2008 APSC Annual President's Environmental Award.

2.1.4.6.3 Pesticides[8]

The mission of DEC's Pesticide Control is to regulate and allow the safe use of pesticides in Alaska in order to protect human health and the environment.

Stipulation 2.2.5.1 in the Lease and Grant requires that APSC receive approval from the SPC for the Lease and the BLM AO for the Grant prior to use of any pesticide on TAPS. Alaska regulations in 18 AAC 90 require permits for application of pesticides on State rights-of-way. The regulations further require that any government official or agency that approves, directs, or conditions the use of a pesticide be certified to apply the pesticide being considered. Close coordination between DEC and the JPO is required to ensure all requirements of Alaska law and the Lease and Grant stipulations are understood and fulfilled as efficiently as possible.

No formal permit applications were submitted for pesticide use along TAPS for FY09. However, coordination of pesticide permit and use issues is an ongoing area of coordination between DEC and the JPO.

[8] 18 AAC 90 & Lease and Grant Stipulations 2.2.5.1 and 4.1

In FY09 APSC began working with DEC to document pesticide use policies and application processes to obtain both a permit from DEC and authorization required through the Grant and Lease. This on-going coordination project will clarify policy for APSC and simplify compliance oversight for all of the JPO agencies.

2.1.4.6.4 Drinking Water[9]

The DEC Environmental Health Drinking Water Program ensures water systems supply water that meets minimum health-based standards as required by the federal Safe Drinking Water Act. DEC provides oversight of system design, installation, operation, and maintenance of drinking water facilities. Activities include review of project descriptions and engineered plans for new and modified systems to ensure standards are met to protect health. Oversight is executed at pump stations, response bases, support facilities, and temporary camps associated with TAPS activities.

Each drinking water system on APSC facilities must comply with regulatory requirements enforced by DEC. Each system's monitoring plan provides a uniquely tailored map to demonstrate that tested water is representative of the water distributed. DEC's oversight is accomplished through preliminary system review and by monitoring required operational records and water testing. Routinely a Sanitary Survey of the permitted system is conducted to ensure proper system construction, operation, and repairs are accomplished and the system is safe to use.

During FY09, surveillance of the drinking water systems was conducted at each of the pump stations and the VMT. Each drinking water system was inspected to ensure proper on-site recordkeeping. The backflow prevention devices were also checked. No discrepancies were found during the surveillance. The Environmental Health Division routinely conducts Sanitary Surveys of permitted drinking water systems to determine regulatory compliance. The results of these surveys were reviewed prior to field observations, and no problems were noted during the review.

2.1.4.6.5 Food Service[10]

DEC's Environmental Health, Food Safety & Sanitation Program's mission is to protect public health at regulated facilities to prevent illness, injury, and loss of life caused by unsafe sanitary practices.

Each of the food service facilities associated with TAPS is required to maintain a current food service permit issued by DEC. Permits are required for permanent and temporary facilities. DEC's oversight includes food services at pump stations and temporary camps used to support projects requiring more housing than can be provided at existing permanent facilities.

During FY09 APSC proposed the activation of several temporary camps to house personnel working on SR at Pump Stations 3 and 4. DEC's Drinking Water, Solid Waste, and Food Safety and Sanitation Programs all coordinated with other oversight

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[9] 18 AAC 80 & Grant and Lease Stipulations 1.20.1 and 4.1

[10] 18 AAC 31 and Lease and Grant Stipulations 1.20.1 and 4.1

agencies at the SPCO (DNR and ADF&G) to accomplish necessary reviews and approvals for these temporary camps. This activity required involvement of the Department Drinking Water, Solid Waste, Food Safety, and Waste Water programs, and coordination with DNR, and ADF&G. A copy of the Department Guidance for temporary camps was provided to SPCO ROW and Permits Section for reference to expedite review of proposals in the future.

2.1.4.6.6 Division of Water[11]

DEC's Water Division oversees the compliance to several EPA- NPDES general permits associated with TAPS. These permits govern excavation dewatering, storm water, and domestic wastewater discharges. In addition to general permits, DEC oversees several specific NPDES permits. On October 31, 2008, the EPA approved the State of Alaska's application to take over issuing and enforcing permits for wastewater discharges issued under the Clean Water Act. The EPA approval triggers a three-year transition from federal to state control of the program. During the transition period, responsibility for developing and enforcing different types of permits will be handed off from EPA to DEC. The transition began in FY09 and will be complete by November 2011.

The DEC Liaison communicated observations from various JPO field personnel to the Division of Water concerning domestic wastewater disposal systems at each TAPS pump station and the VMT. Each facility with domestic wastewater discharge was reviewed along with APSC environmental generalists for compliance to site specific and general requirements for domestic wastewater discharge under APSC Environmental Protection Manual, EN-43, and Grant and Lease Stipulation 2.2.2.1. In addition, the Solid Waste Disposal sites and active material sites were reviewed for compliance to storm water runoff regulations. There were no issues identified during this effort.

APSC continues to work on the VMT Ballast Water Treatment facility redesign, Project # Z576. The Division of Water continues oversight and coordination with JPO agencies. The NPDES permit for the BWT facility will expire in 2009. While DEC is taking primacy for the NPDES program from EPA, DEC has yet to receive primacy for this section of the NPDES program. NPDES permit renewal for the BWT permit will be managed by the EPA.

2.1.4.6.7 Division of Air Quality[12]

The mission of the Air Permits Program is to protect the Alaskan environment by ensuring that air emissions from industrial operations in the state do not create unhealthy air.

During FY09, open burning and dust suppression were the most prevalent activities requiring oversight. Both activities are regulated by 18 AAC 50, but neither of them requires a permit from DEC. Dust suppression is routinely conducted at TAPS pump stations and project sites. Dust suppression normally requires a water use permit from

[11] Water Quality, 18 AAC 70; Wastewater, 18 AAC 72; Alaska Pollution Discharge Elimination System (APDES), 18 AAC 83; Lease and Grant Stipulations 2.2.2.1 and 4.1

[12] Air Permits Program: 18 AAC 50 and Lease and Grant Stipulations 2.2.1.1, 2.2.4.1, 2.2.4.2, and 4.1

the landowner, and those permits are coordinated with DNR as necessary. Open burning is typically conducted by APSC to reduce the volume of wood waste, which allows for more efficient use of space in SWD sites that are permitted along TAPS.

The Air Permits Program became actively involved with APSC in the BWT facility Project #Z576 when incorporation of thermal oxidizers into the system required the Air Quality Permit for the VMT to be modified. The DEC Air Quality and Water Divisions continue to review the pertinent aspects of facility alterations to ensure compliance with existing permits and to determine if permit modifications.

During FY10, the DEC Liaison will coordinate with other JPO agency representatives to review various air program and permit requirements for TAPS and the VMT. This review will concentrate on compliance with policies and procedures, by APSC, as outlined in EN-43. The DEC Liaison will ensure the review is conducted in collaboration with DEC's Air Permits Program personnel.

2.1.4.7 Alaska Department of Fish & Game

The ADF&G Liaison conducted field inspections of the TAPS Right-of-Way with an APSC representative (APSC Fish and Wildlife SME) at various locations along the 800-mile pipeline from the North Slope to Valdez. Pre- and post-project sites were visited and written surveillances were completed at a representative sample of the locations (Table 8. ADF&G Permit and Project Review Statistics, FY05 through FY09).

Permit Issuance and Field Activity Summary

The ADF&G processed 44 total reviews and permits in FY09 (39 Fish Habitat Permits and 5 written comments on other agency permits). The ADF&G Liaison traveled the entire 800 miles on, or adjacent to the pipeline corridor visually inspecting a representative sample of cross-channel structures, and writing a detailed written surveillance on a subset of those which will be entered into the JPO document tracking system (with corresponding photographs).

Table 8. ADF&G Permit and Project Review Statistics, FY05 through FY09.

Permit & Field Activity Summary	FY05	FY06	FY 07	FY08	FY09
Total Reviews and Permits Issued	58	56	68	51	44
Fish Habitat Permits Issued	46	39	54	43	39
Hazing Permits Issued	0	0	0	0	0
"No Permit Required" Letters	4	1	1	3	0
Fish Habitat Permit Denials	0	0	0	0	0
Withdrawn Applications	2	0	2	0	0
Written Comments on Other Agency Permits	6	16	11	5	5
Compliance Reviews – Permits, Lease, Grant		36	49	54	47
Total Field Reviews / Total Field Days	70/14	68/14	66/15	124/14	77/13

Surveillances
In FY09, the ADF&G Liaison conducted 47 surveillances along the TAPS ROW. Most of these surveillances, 30, involved LWC. Figure 31 is a photograph of the upper Becky Creek LWC, which allows access to a known Arctic grayling overwintering area upstream.

Figure 31. *Upper Becky Creek LWC.*

The remainder included a mix of culvert inspections, revetments, guide banks, and ramps. One such culvert inspection was conducted on Slate Creek near TAPS PLMP 408.35. The main channel culvert was replaced by a 10-foot diameter by 70-foot long corrugated metal pipe culvert. The overflow culvert was replaced by another 5-foot diameter corrugated metal pipe culvert. The culvert was properly installed; it replicated natural-stream channel conditions within the barrel. Sediment transport, flood and debris conveyance, and fish passage function as they would in a natural channel. The culvert has been sized to match (at least 90 percent) the natural channel width (reference reach). The culvert was buried at least 20 percent and the pipe backfilled with a layer of Class I riprap, gravel, and fines to simulate natural channel materials. Class I riprap, gravel, and fines were placed as an apron at the culvert outlet to preclude scour pool formation, and prevent French draining. This is a good example of a proper culvert installation. Figure 32 is a photograph of culvert at Slate Creek, taken in 2001, that illustrates susceptibility to perching at the culvert inlet.

Figure 32. *Slate Creek culvert, 2001.*

Figure 33 shows the Slate Creek culvert in 2009, after APSC remediation was completed. The culvert was imbedded to reduce the likelihood of perching and to provide fish passage during low-flow conditions. The smaller diameter culvert was installed to manage overflow during high-water conditions.

Figure 33. *Slate Creek culvert, 2009.*

Five of the surveillances discovered action items that APSC corrected on the spot. There were three unsatisfactory surveillance reports in FY09:

1. Shorty Creek, located at PLMP 400.50, received an unsatisfactory surveillance because a grade break (streambed elevation change) developed immediately upstream of the culvert. A comparison of photographs taken after construction (in 2004) with photographs taken in 2008 verified that this grade break occurred after

the culvert was installed. A line wide Fish Habitat Permit was in-place to complete the corrective work by-hand. APSC promptly corrected the fish passage issue soon after receiving a copy of the surveillance.

2. Haggard Creek, located at PLMP 642.48, was the site of a new culvert installation in 2007. Prior to the installation, a bridge had been removed and the crossing became a blockpoint for several years. During this past winter, the culvert became blocked with ice and the subsequent overflow severely eroded the road surface. The area is prone to icing and this type of event is likely to occur again in the future. Site repair is expected to be completed under the programmatic approach utilized by APSC to detect deficiencies and perform corrective work in a timely manner.

3. Hess Creek, PLMP 378.6 received an unsatisfactory surveillance report for non-compliance with Lease Stipulation 2.4.3.1. Against the advice of the JPO Habitat Biologist in 2005, APSC installed rock vane structures that are angled downstream and designed to be overtopped at ordinary high water, or near bankfull flows (see Figure 34). This configuration redirects flowing water into the bank (or floodplain) that is being protected, thus exposing it to direct erosion during bankfull flows. As a result, the constructed floodplain has now eroded to within 13 feet of the upper terrace (at its closest point). Figure 35 for illustrates the current state of the location. An estimated 1,100+ cubic yards of gravel material and about 160 linear feet of willow cuttings (live dikes) placed between the rock vanes have eroded into the active channel during four mild break-up events and were transported downstream. The ADF&G recommends that this experimental design not be used in the future.

Figure 34. *Hess Creek, 2005.*

Figure 35. *Hess Creek, 2009.*

APSC Environmental Surveillances and Repairs

Fish stream surveillances were conducted at 648 sites along the TAPS ROW. Civil Maintenance personnel worked on 51 of those drainage structures in 2008. Four sites (<1%) required extensive repair (and Fish Habitat Permits) to provide long-term fish passage, 47 sites (>7%) required routine maintenance (under the line-wide Fish Habitat Permit), and the remaining 597 sites (92%) required no work.

One example to illustrate the APSC Civil Maintenance Program monitoring of fish passage is the channel changes and fish passage problems at Beaver Dam Brook (stream). These problems were first observed and monitored by members of the APSC Environmental Team and Civil Maintenance Program. The ADF&G has been advised that APSC is actively working on a solution to the site problems to correct fish passage. Since APSC has detected the deficiency (using their Environmental Surveillance Program), reported the fish passage deficiency to the ADF&G, and is actively working on a solution to reestablish fish passage, the ADF&G will not issue a Notice of Violation for failure to provide efficient fish passage at this location during 2009. In the interim, APSC is expected to continue working on a rapid solution to re-establish fish passage and keep the ADF&G informed of their progress. The site did receive an unsatisfactory observation on Surveillance Report 09-TAPS-S-086 for failure to provide fish passage as required in Grant Stipulation 2.5.1. The ADF&G is concerned that if the problem is not fixed prior to the spring breakup, Arctic grayling migration into Beaver Dam Brook may not occur in this spawning and rearing area.

Figure 36. *Beaver Dam Brook.*

Figure 37. *Beaver Dam Brook confluence with the Dietrich River.*

Environmental Situation at the VMT Tanker Berths

During recent years, workers at the Valdez Marine Terminal observed an increased number of nesting black-legged kittiwakes (*Rissa tridactyla*) on the Tanker Berths. Kittiwakes' use of the VMT will potentially increase in the future. Increased nesting activity has caused a variety of safety and environmental issues. There are four primary concerns related to the increase in nesting kittiwakes on the berths, including increased:

1. Risk to health and safety of workers on active and inactive berths,
2. Risk of incidental takes of nests and young on active berths,
3. Potential for large numbers of birds to become injured or oiled during an incident or oil spill response; and;
4. Potential for delays of maintenance during the nesting season, resulting in increased safety and environmental risks.

The kittiwakes use the berths as a sanctuary. In 2004, APSC attempted to move the birds from the berths and eliminate this sanctuary. Displaced birds moved to other locations when the exclusion devices and active hazing caused the kittiwakes to shift their activities. This program was discontinued in 2005 and 2006 and the birds returned in increased numbers. The U.S. Fish and Wildlife Service (USFWS) recently estimated the kittiwake population at the tanker berths at 12,000 birds (4,500 active nests). This colony has been designated the “Dayville Colony” by the USFWS and is considered the third largest kittiwake colony in Prince William Sound.

In mid-2007, APSC partnered with villagers from Tatitlek and Chenega to conduct a subsistence harvest of gull eggs within the VMT (with limited success). In 2008, APSC acquired a Migratory Bird Depredation Permit from the USFWS, which authorizes certain management and control activities (harvest up to 100 eggs and test nesting exclusionary devices) necessary to provide for human health and safety, protect personal property, or allow resolution of injury to people or property. In the spring of 2009, APSC initiated a project to install exclusionary netting on the berths as a nonlethal control technique to solve the problem.

River and Floodplain Monitoring

Maintenance Coordinators and Engineers from APSC have conducted River and Floodplain Monitoring since the construction of TAPS. This monitoring program is accomplished by using aerial surveillance to observe and document changes in river environments that may affect the TAPS. The ADF&G received the list of preliminary recommendations of sites needing “corrective maintenance” and “predictive maintenance” (corrective maintenance was recommended in 2008; predictive maintenance needs to be prioritized, planned and scheduled in 2009 or later years). APSC requested ADF&G input on project timing and scope to avoid or minimize impact to fish and wildlife resources and habitats. During FY09, the ADF&G provided the requested information to APSC during the early planning stages of those future projects.

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2.2 Trans-Alaska Gas System (TAGS)

2.2.1 Trans-Alaska Gas System (TAGS) - Conditional Lease Closure

In the late 1980s, Yukon Pacific Corporation (YPC), a business unit of CSX Corporation, proposed to construct a 797-mile gas pipeline from Prudhoe Bay on the North Slope to Anderson Bay near Valdez. At Anderson Bay, YPC proposed to develop a liquefied natural gas plant and marine terminal. The project would have included a gas-conditioning plant on the North Slope and a large diameter, chilled and buried pipeline paralleling TAPS. The TAGS pipeline was to include several compressor stations built along the route, terminating at Anderson Bay, approximately three miles west of the TAPS crude oil terminal. On December 11, 1988, DNR issued a 10-year conditional lease, ADL 413342. If the lease conditions were met, YPC would have been able to enter into a lease under the Right-of-Way Leasing Act (AS 38.35). The conditional lease was renewed for another 10-year term in 1998.

In October 2008, YPC requested a second 10-year renewal of their conditional pipeline ROW lease. The SPCO coordinated with the Office of the Attorney General to prepare an extensive analysis and decision document. On December 10, 2008, the request for renewal of ADL 413342 was denied by the DNR Commissioner. In January 2009, YPC requested reconsideration of the December 10, 2008 decision. The request was accepted, the decision was reconsidered, and the Commissioner again denied the request to renew the lease.

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3.0 SOUTHCENTRAL PIPELINES

Pipelines that cross state lands within the Southcentral Region of Alaska, and that are authorized by ROW leases granted under AS 38.35 fall under the jurisdiction of the SPCO. The following section of this report will discuss the two Southcentral pipeline systems over which the SPCO exercises jurisdiction – the Kenai Kachemak Pipeline (KKPL), operated by Marathon Pipe Line, LLC, and the Nikiski Alaska Pipeline, operated by Tesoro Alaska Pipeline Company. The general route of both of these pipelines is depicted below in Figure 38. The discussion of each system is organized to include an overview describing the pipeline, highlights from the lessee's annual report, and a summary of pertinent activity by SPCO officials for that particular pipeline system.

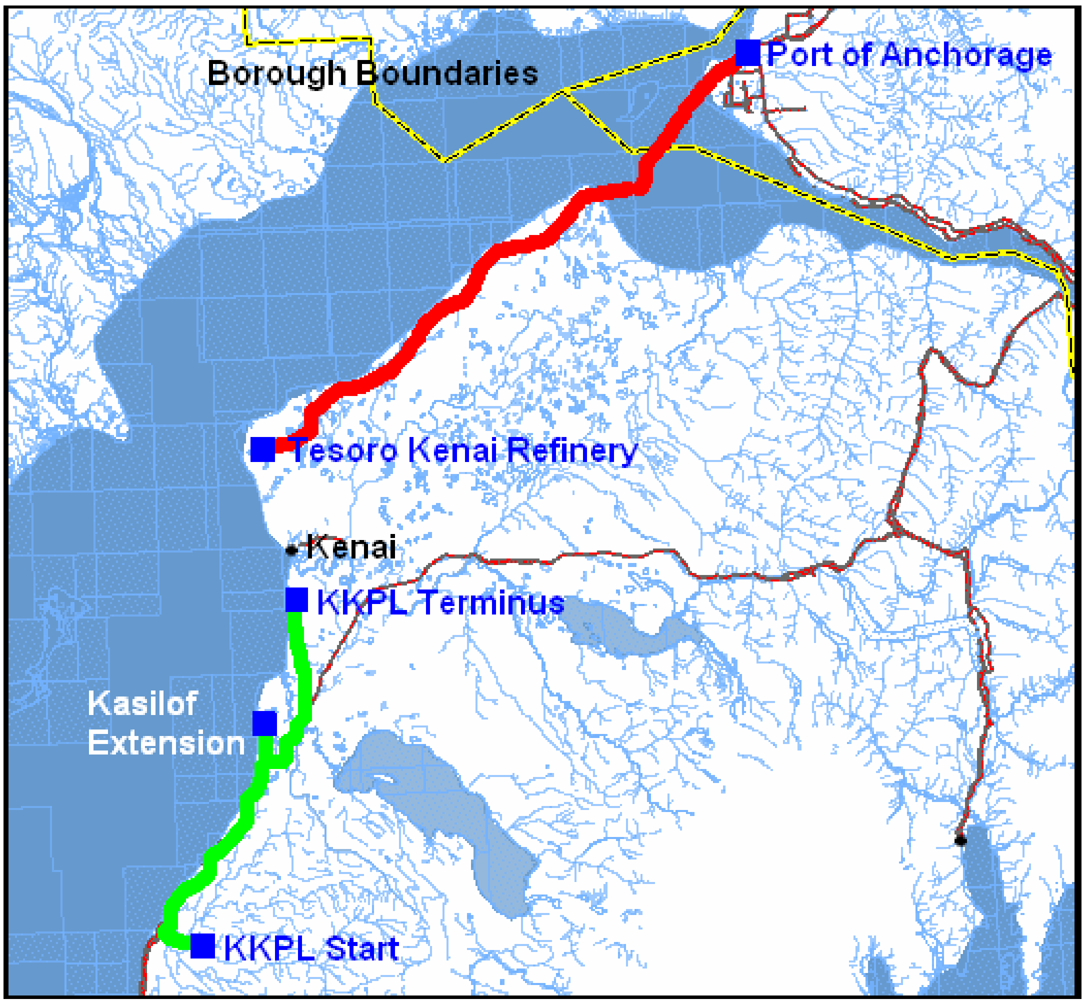

Figure 38. *Area map of SPCO Jurisdictional Southcentral Pipelines*

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3.1 Kenai Kachemak Pipeline

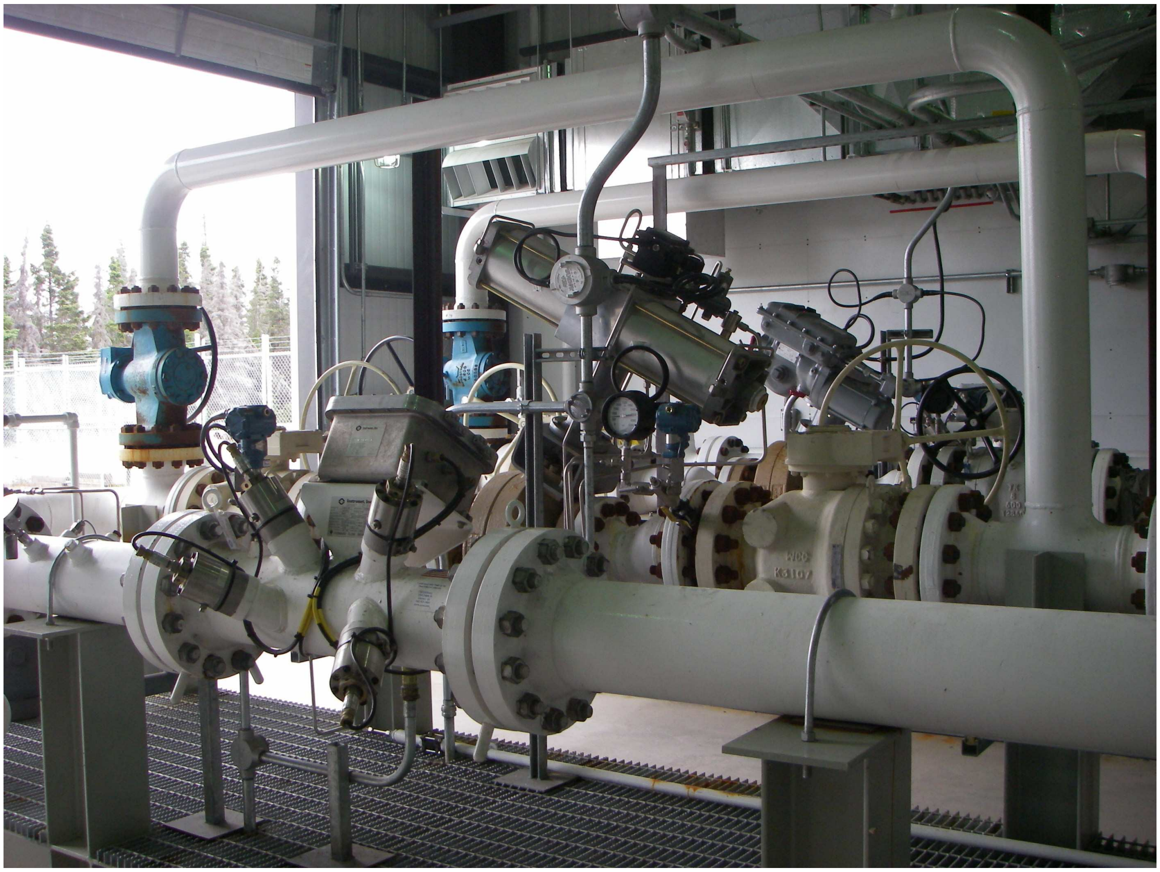

Figure 39. *KKPL, inside the 500 Master Meter Building.*

3.1.1 Right-of-Way Lease and Pipeline System Overview

The Kenai Kachemak Pipeline is a high-pressure, primarily buried, natural-gas transmission pipeline on Alaska's Kenai Peninsula. Throughout its route, the pipeline parallels Kalifornsky Beach Road, the Sterling Highway, Cohoe Loop Road, and Oilwell Road. It was built in three phases during 2003, 2004, and 2006. The KKPL mainline was built with 12-inch pipe of 0.330 and 0.500-inch wall thickness, and is rated for a maximum allowable operating pressure of 1,480 psig. Specific physical characteristics of the pipeline and extensions are provided in Appendix E, Physical Characteristics of SPCO Jurisdictional Pipelines.

KKPL begins at the Happy Valley production pad and ends at the Marathon Oil Company 500 Master Meter Building (Figure 39), running generally south to north. Seven Cook Inlet wells currently transport natural gas through KKPL. Some natural gas is distributed from KKPL for local use.

The original ROW lease was issued to KKPL, LLC, on November 26, 2002. The lease has been amended twice and is set to expire on November 25, 2032. The first amendment, executed on June 16, 2004, added 48 acres to the ROW to accommodate Phase 2 of construction, referred to as the Happy Valley Extension (HVE). The second amendment, executed on April 24, 2006, added 35.6 acres of state land for construction of Phase 3, referred to as the Kasilof Extension (KE). Appendix G, Acreage, Survey, and Lease Information, contains additional lease information.

The *ROW Release of Interest* was finalized in FY09 and reduced the ROW from the construction width of 60-feet to the operational width of 20-feet. Specific acreage amounts associated with the construction and operational ROW width are provided in Appendix H, Pipeline ROW Lease Appraisal Information.

For most of the Lessee's reporting period, the operator of KKPL was Norstar Pipeline Company. Beginning September 2008, Marathon Pipe Line, LLC became the pipeline operator.

3.1.2 Lessee's Annual Report

The Annual Report for Kenai Kachemak Pipeline was submitted in January 2009 and amended on March 23, 2009 (Appendix J, SPCO Reporting Requirements). The SPCO reviewed the Kenai Kachemak Pipeline 2008 Annual Report and found that it provided sufficient information to satisfy the lease requirement. (SPCO Letter No. 09-011-WW).

The summary below highlights just a few of the more significant KKPL activities including One-Call program participation, corrosion-associated inspections, cathodic protection inspections, and documentation of the regularly conducted aerial patrols, excerpted from the Annual Report.

Throughput and Pigging

KKPL, LLC, reported pipeline throughput and pigging activities in their 2008 annual report. This information has been summarized in Table 9.

Table 9. Throughput and Pigging Information for KKPL, 2008.

Pipeline System	2008 Throughput	Maximum Operating Pressure (MOP)	Maintenance Pigging	Last Smart Pig Run	Pipeline Operator
KKPL	21.77 MMcfpd	1,480 psig	No regular schedule	2005	NORSTAR-Marathon Pipe Line

Safety

The KKPL operator reported no lost time incidents or recordable accidents/injuries during 2008, for either operator personnel or contractors and material providers. It was also reported that there were no discharges of oil or hazardous substances by Norstar or Marathon Pipe Line during 2008.

As part of its public safety efforts, the operator participates in the *One-Call* damage prevention program. In 2008, there were 148 locate requests, which resulted in 38 onsite locates, and 13 high-pressure standbys. The One-Call program is important to the community and key to prevention of third-party pipeline damage that could threaten public safety. The majority of this activity took place during summer months. With the exception of high pressure standbys, the number of locate requests and onsite locates were almost half of what they were in 2007.

Corrosion Protection

To minimize the potential for internal corrosion, the operator regularly sampled gas for quality, hydrogen sulfide (H2S) and water content. The operator monitors to the requirements of 49 CFR 192.475 and 49 CFR 192.477. Data from the sampling efforts were submitted to the SPCO in the annual report. The gas content was reported as consistently greater than 99% methane. Hydrogen Sulfide is minimal and ranged from 0-0.3 parts per million.

Cathodic Protection

The operator inspects rectifiers a minimum of six times during the year. The rectifiers for KKPL were inspected 12 times in 2008. As part of their cathodic protection program, a pipe-to-soil survey is completed once a year and coupon current readings are taken periodically at four locations along the KKPL and every mile of the KE. A pipe-to-soil survey was completed in December 2008.

Valve Inspection and Maintenance

The mainline valves were inspected and serviced by Norstar on July 14 and 15, 2008. Inspection and testing of relief devices and pressure regulating stations was performed on August 21, 2008. No deficiencies with the mainline valves were reported.

Leak Surveys

Norstar conducted two leak surveys in 2008. The first survey was conducted on January 22, 23, and 24, 2008. The second survey was performed on July 15, 2008 through July 17, 2008. No leaks were reported during either survey.

Aerial and Ground Surveillance

There were 25 aerial patrols of the KKPL during 2008. During those flights, and other drive-by inspections, personnel routinely checked the pipeline and the ROW for encroachments, construction activities, any unauthorized activities, or changes in the condition of the ROW. There were no major findings during 2008.

3.1.3 Oversight Activities of the State Pipeline Coordinator's Office

(*This section provides a summary of SPCO activities. Information in this section reflects the work efforts of the State Pipeline Coordinator's Office and is not taken from the Lessee's annual report. By the nature of the SPCO work, there will be some overlap of information.)*

During FY09, the SPCO focused on the Surveillance and Monitoring Program (SMP), construction ROW relinquishment, appraisal and rental adjustments, and operator transition. These activities are presented, in more detail, below:

SPCO Compliance Section

Field Trips and Meetings

On June 26, 2008 and May 19, 2009, SPCO staff, accompanied by Marathon Pipe Line, LLC representatives, inspected the entire pipeline ROW and associated facilities. Surveillances conducted on these trips all reflect satisfactory conditions (SPCO Letter

No. 08-043-CT). Figure 40 is a photograph of the pig launcher at the HVE taken on the May 2009 trip. A request from SPCO regarding the status of MPLDOT006 – Integrity Management Risk Management Process Standard, remains open.

Figure 40. *KKPL pig launcher at the HVE.*

SPCO and Marathon Pipe Line, LLC met on March 31, 2009 to discuss their performance in 2008 and their projects and plans for 2009. The KKPL Quality Assurance Program (QAP) and SMP were reviewed and Marathon Pipe Line, LLC agreed to clarify several items.

<u>SPCO Right-of-Way Section</u>

Construction ROW Release of Interests:

On December 10, 2008, the SPCO sent a letter (SPCO Letter No. 08-117-TG) to Kenai Kachemak Pipeline, LLC transmitting an Executed Release of Certain Interests in Lands documents. The letter also provided a copy of the Analysis and Recommendations of Release of Interests in Kenai Kachemak Construction ROW. During a field inspection and records review, the SPCO verified that previously disturbed state lands that required stabilization, re-vegetation, or restoration within the construction ROW had been restored, and were in acceptable condition. A release of interests in the construction ROW effectively reduces the ROW to the width necessary for pipeline operation and maintenance. The Release of Certain Interests documents were recorded in April in the Homer Recording District as Document 2009-001356-0 and in the Kenai Recording District as Document 2009-003780-0.

Unconditional Guaranty Accepted:

On October 29, 2008, the SPCO sent a letter to Kenai Kachemak Pipeline, LLC requesting financial information about the guarantors of the lease. On June 25, 2009, the SPCO received an Unconditional Guaranty from Chevron Corporation for the Lease. After considering the information submitted, the SPCO accepted the unconditional guaranty of Chevron Corporation for Kenai Kachemak Pipeline ROW Lease and determined that the guarantee satisfied the obligation of KKPL to furnish other security or undertaking to protect the public from damage for which KKPL may be liable (SPCO Letter No. 09-081-TG).

3.2 Nikiski Alaska Pipeline

Figure 41. *Nikiski Alaska Pipeline, Mainline Valve 2.*

3.2.1 Right-of-Way Lease and Pipeline System Overview

Nikiski Alaska Pipeline, referred to by the Lessee as the Tesoro Alaska Pipeline, is a buried pipeline that begins at Tesoro Alaska Pipeline Company's (Tesoro) Kenai Refinery in Nikiski. The pipeline route runs along the Kenai Spur Highway through the Captain Cook State Recreation Area, and then parallels the coast to Point Possession before crossing the Turnagain Arm. The pipeline route continues along the Tony Knowles Coastal Trail, through the Ted Stevens Anchorage International Airport, then along Northern Lights Boulevard. The pipeline runs near the Alaska Railroad ROW for the remainder of the route, terminating at the Port of Anchorage. Figure 42 is a route map of the pipeline that was provided by the Lessee.

The ROW lease, ADL 69354, was executed on January 30, 1976 and is scheduled to expire January 29, 2031 (Appendix G, Acreage, Survey, and Lease Information for SPCO Jurisdictional Pipelines). The Lease has been amended four times. The pipeline ROW is typically 10 feet wide for operations and maintenance (Appendix H, Pipeline Lease Appraisal Information). The total system length is 52.8 miles, 20 miles located on state land, occupying 64.2 total acres of state land (Appendix E, Physical Characteristics of SPCO Jurisdictional Pipelines).

The Nikiski Alaska Pipeline was constructed in 1976 with pipe that varies in wall thickness from 0.188 to 0.625 inches. The pipeline has a 10.75-inch outside diameter and transports refined petroleum products, including jet fuel, gasoline, and diesel, from Tesoro's Kenai Refinery to the Port of Anchorage. The pipeline transports refined products suitable for industrial, government, commercial, and consumer use, and operates under USDOT pipeline safety regulations. The Nikiski Alaska Pipeline's maximum operating pressure (MOP) is 1,440 psig. Mainline pumps, meters, and pig launcher are located at Tesoro's Kenai Refinery. Specific physical characteristics of the pipeline are provided in Appendix E.

The Nikiski Alaska Pipeline was last inspected with a smart pig in January 2007. Maintenance pigs are not routinely used, but batch pigs, used to separate batches of different products transported through the pipeline, are used.

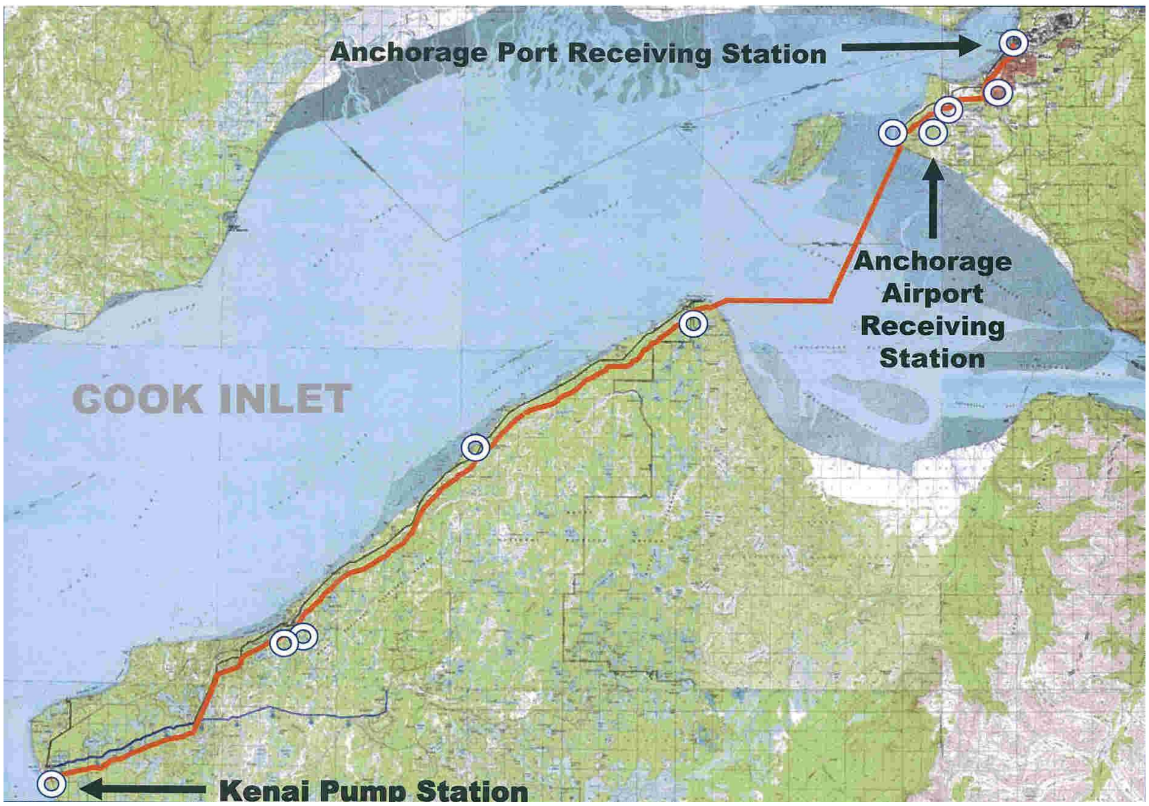

Figure 42. *Nikiski Alaska Pipeline route map, provided by Tesoro Alaska Pipeline Company.*

3.2.2 Annual Report

Tesoro submitted their original *2008 Annual Comprehensive Report on Pipeline Activities and State of the Pipeline System* on January 16, 2009 with a revision sent a few days later. The Compliance Section reviewed both documents against minimum annual reporting requirements and requested additional information on the state of the pipeline system in SPCO letter No. 09-003-CT. Tesoro provided the requested information on March 16, 2009. All open issues regarding the annual report were closed with SPCO letter No. 09-017-CT. The summary below highlights some elements documented in the Lessee's 2008 Annual Report:

Throughput, Pigging and Reliability

Tesoro reported no abnormal operating conditions during 2008. The throughput and pigging information are provided in Tables 10 and 11. The Nikiski Alaska Pipeline was 99.77% reliable in 2008. The pipeline transports refined products and its throughput is typically based upon end user demand, not operational readiness. Conforming to requirements of 49 CFR 195.406(b), Tesoro operates with a MOP of 1,440 psig. Tesoro notes that operating procedures and shutdown devices are in place to prevent the pressure from exceeding 110% of MOP, as specified in 49 CFR 195.406(b).

Table 10. Throughput and Pigging Information for Nikiski Alaska Pipeline, 2008.

Pipeline System	2008 Throughput	MOP	Maintenance Pigging	Last Smart Pig Run	Pipeline Operator
Nikiski Alaska	11,400,129 barrels	1,440 psig	No regular schedule	January 2007	Tesoro

Table 11. Refined Product Transported through the Nikiski Alaska Pipeline in 2008.

Product	2008 Throughput
Jet-A	5,769,277 barrels
Unleaded gasoline	3,557,614 barrels
Premium unleaded	482,141 barrels
Ultra-low-sulfur Diesel (ULSD)#1	949,895 barrels
ULSD #2	641,202 barrels
Total	*11,400,129 barrels*

Tesoro participates in the *One-Call* damage prevention program through Alaska Digline. Notifications of excavation work being performed near the pipeline were sent to Tesoro for evaluation. There were 598 one-calls regarding dig activities in the vicinity of the pipeline in 2008. The more important third-party excavations near the pipeline included:

- Chester Creek, work on Anchorage's Aquatic Habitat Restoration project;
- On the ROW between Milepost 60 and 62 Alaska Communications System Fiber Optics installed a project using Horizontal Direct Drilling;
- At the Port of Anchorage, the Alaska Railroad worked on the Intermodal project;
- At Daniels Creek, a bridge had been previously installed. It crossed the pipeline. Tesoro had to backfill two areas that resulted from ConocoPhillips' 2007 excavations.

Tesoro recorded no instances of third-party damage, no instances of exceeding the MOP, and no reportable USDOT Safety Related Conditions for 2008.

Per 49 CFR 195.402(a), Tesoro has developed and periodically reviews a written operations and maintenance manual. Tesoro reviewed the entire manual in January 2008 and revised the records retention, Material Safety Data Sheets, and contact phone number sections.

Corrosion Management

Tesoro recorded rectifier readings monthly. The annual cathodic protection survey was completed in July 2008 by a third-party engineering consultant. The 2008 Annual Cathodic Protection Survey contained eight recommendations for adjustments and maintenance. An ILI of the ASIG lateral was conducted during February 2009. Confirmation digs were scheduled for the second quarter of 2009.

Cathodic Protection

The portions of the Tesoro pipeline that are underground are protected from external corrosion by an impressed current CP system. The CP system is inspected and tested annually to determine whether the level of cathodic protection is adequate per 49 CFR 195.573(a)(1). The 2008 survey for the Nikiski Alaska Pipeline resulted in system upgrades. The main upgrade was installation of a deep well anode to replace an anode ground bed, installed at Mainline Valve No. 5, near Point Possession.

The 2008 annual CP survey report contained the following recommendations for adjustments and maintenance:

- Continue the installation of coupon monitoring stations on the Anchorage side of the pipeline system (this is an ongoing action);
- Install coupon test stations, with test leads to the pipeline and/or casing, near the corner of Wisconsin St. and Northern Lights Blvd. (A coupon test station was installed near the corner of Wisconsin and Northern Lights in September 2008. The casing could not be accessed to install test leads to it. Coupon test stations with casing leads will be installed in 2009);
- Perform additional testing, when the casings are exposed, to determine if the pipeline is shorted to any of the casings. Coordinate this activity with ENSTAR Gas Company, as their pipeline shares the same right-of-way in this area (this is an ongoing action);
- Install a new coupon test station with new test leads to the Tesoro and Flint pipelines and casing located at this site. Install a shunt to measure the bond current between the pipelines (this will be installed in early to mid-2009);
- Install new coupon monitoring stations on the ASIG lateral. (The station was added. Other coupon test stations will be added during any future excavations);
- Clear the short that exists on the stainless tubing in contact with the pipe at the Anchorage Terminal (his is an ongoing action);
- Continue performing and recording monthly rectifier readings (this is an ongoing action); and
- Continue performing and recording annual cathodic protection surveys (this is an ongoing action).

The SPCO observed the drilling phase of Tesoro's cathodic protection project in April 2008.

Valve Inspection and Maintenance Activities

Tesoro reported that pipeline ROW vegetation was cleared in 2008 within the ROW boundaries. During 2008, Tesoro brushed the ROW from mileposts 0 to 13, 18 to 46, and 60 to 66. As required by PHMSA, and as part of the Operator's monitoring program, Tesoro inspected the mainline valves on eight occasions.

Aerial and ground Surveillance and Monitoring Activities

Tesoro reported that employees performed 81 ROW inspections in 2008. There were no deficiencies noted on any of the inspections. Tesoro inspects the sub-sea pipeline crossing under the Turnagain Arm every 5 years. This inspection is performed by a company that specializes in this type of procedure. The side-scan sonar survey shows hazard conditions near the pipe. The most recent side-scan sonar survey of the underwater pipeline, performed in 2006, indicated no features near the submerged pipeline that would pose a risk.

Federal regulation 49 CFR 195.410 requires that Tesoro maintain line markers over buried pipeline sections. In 2008, one ROW marker was replaced near Aero West on Northern Lights Boulevard in Anchorage.

Public Awareness and Damage Prevention

Tesoro's public awareness program was revised in October 2008. This revision included document reformatting to reflect organizational changes and program clarification.

3.2.3 Oversight Activities of the State Pipeline Coordinator's Office

(*This section provides a summary of SPCO activities. Information in this section reflects the work efforts of the State Pipeline Coordinator's Office and is not taken from the Lessee's annual report. By the nature of the SPCO work, there will be some overlap of information.)*

SPCO Compliance Section staff conducted a surveillance of the Nikiski Alaska Pipeline on June 1, 2009. This trip included a records check in Tesoro's Kenai Offices and an aerial inspection of the ROW from the Kenai refinery to Point Possession. SPCO letter No. 09-028-CT, transmitted 11 surveillance reports and field notes to the lessee in support of the surveillance field trip. The aerial inspection proved satisfactory, but the records check revealed some deficiencies, primarily related to supporting documentation for the QAP and the compliance of Tesoro contractors with the terms of the ROW lease stipulations.

Tesoro submitted their current QAP to the SPCO. Following a review of Tesoro's QAP, both parties the program, Tesoro and the SPCO met to better define the elements of the program and to insure that it meets both the operator and regulator's needs. These issues will be reported more fully in the FY10 SPCO annual report.

SPCO letter no. 09-002-CT describing a surveillance trip conducted in FY08 was sent to the lessee on January 26, 2009. Four follow-up items have been addressed by Tesoro and were closed out by the SPCO just after the close of FY09.

3.2.4 State Fire Marshal's Office

Annual Fire Prevention and Life Safety Inspections of the Nikiski Alaska Pipeline facilities were conducted by John Cawthon of the Alaska Division of Fire and Life Safety Inspection on March 24, 2009. The inspections covered the AFSC Receiving Facility, Port Control Offices, and General Warehouse located at the Port of Anchorage. The inspections were successfully conducted with the cooperation of the Tesoro Alaska Pipeline Company. No violations were found during the inspection of Nikiski Alaska Pipeline facilities.

4.0 North Slope Pipelines

Pipelines that cross state lands located on Alaska's North Slope, and that are authorized by a ROW lease granted under AS 38.35 fall within the jurisdiction of the SPCO. The following section of this report discusses seven pipeline systems located on the North Slope over which the SPCO exercises jurisdiction. These particular pipeline systems are operated by ConocoPhillips Alaska, Inc. (CPAI), BPXA, or the North Slope Borough (NSB). The systems include Alpine, Badami, Endicott, Kuparuk/Oliktok, Milne Point, Northstar, and Nuiqsut. The general route of these pipelines is depicted below in Figure 43. The discussion that follows is organized to include an overview that describes the pipeline, highlights from the lessee's annual report, and a summary of pertinent activity by SPCO officials for that particular pipeline system.

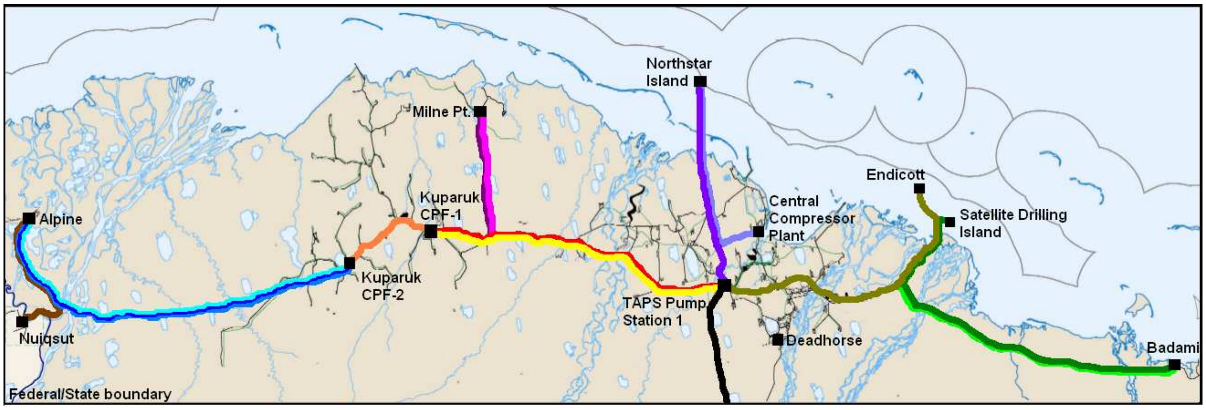

Figure 43. *Map of SPCO North Slope Area Pipelines.*

- Alpine Oil Pipeline*
- Alpine Diesel Pipeline
- Alpine Utility Pipeline
- Badami Sales Oil Pipeline*
- Badami Utility Pipeline
- Endicott Pipeline*
- Kuparuk Oil Pipeline*
- Kuparuk Pipeline Extension*
- Milne Point Oil Pipeline*
- Milne Point Products Pipeline
- Northstar Oil Pipeline*
- Northstar Gas Pipeline
- Nuiqsut Natural Gas Pipeline
- Oliktok Pipeline
- Trans-Alaska Pipeline System (a portion of)*

**AS 38.35 crude oil pipeline leases*

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4.1 ConocoPhillips Alaska Operated Pipelines

Assurance Programs

The various pipeline companies owned in part by ConocoPhillips each have a contract with ConocoPhillips Alaska Inc. to operate their respective pipelines. Each pipeline company, together with CPAI, implements a number of assurance programs that govern their operations including those operations associated with the AS 38.35 jurisdictional pipelines for Alpine, Kuparuk, and Oliktok. These programs are in place to assure personnel safety, environmental protection, integrity of the infrastructure and timely intervention. At a high level, these assurances are reflected in Quality Programs, the Health, Safety, and Environmental Management System Standard, the Quality Management Systems, and the Operations Compliance Management System (OCMS). Additionally, all of the AS 38.35 pipelines come under the authority of the PHMSA with respect to pipeline integrity. PHMSA is a partner agency within the JPO. The Quality Programs, required by the respective lease stipulations, define some elements to be included as part of the company's quality system.

Health, Safety, and Environmental Management System Standard

The Health, Safety, and Environmental Management System Standard identifies the processes required to assess and manage the operational risk to the business, its stakeholders, and the environment. CPAI revised the following Health, Safety, and Environmental Policies in 2008: Blood-borne Pathogen, Contractor Performance, Hazard Communication, Hexavalent Chromium Management, Hydrogen Sulfide Safety and Health, Natural Occurring Radioactive Material, Respiratory Protection and Weapons. An internal compliance audit was performed by CPAI on the system in 2008. There were no major findings.

Quality Management System

The purpose of the Quality Management System is to make sure that facilities and equipment are designed, built, and operated in compliance with all codes, standards and regulations aimed at assuring system integrity. This program is under the oversight of CPAI and it includes criteria that align it with the ISO 2000 / 9000 philosophies (international standards).

Operations Compliance Management System (OCMS)

The OCMS offers a systematic approach for ensuring that pipeline operations remain in compliance with applicable laws, regulations, and ROW lease requirements. There were six assessments associated with the OCMS in 2008. The assessments covered Operations and Maintenance Procedures, the Anti Drug and Alcohol Misuse Prevention Program, the Operator Qualification Program, ROW Lease/Grant Stipulations, Preventative Maintenance Orders, and SCADA and Human Factors. Final reports were completed for all but the Operator Qualification Program and the ROW Lease/Grant and Stipulations assessments. All findings from the Operations and Maintenance Procedures and the Anti Drug and Alcohol Misuse Prevention Program assessments were closed in 2008, leaving findings from the Preventative Maintenance Orders and SCADA and Human Factors assessments open in 2009. The SPCO expects to see the findings from the last two assessments closed out in the 2009 annual report. An assessment plan for the OCMS was also under development and implementation was planned for the first quarter of 2009.

Risk Management Programs

The Risk Management Program for the CPAI operated pipelines is divided into seven categories; Acquisition and Divestiture, Design and Construction, Operations and Maintenance, Environmental Management, Waste Management, Emergency Management and Response, and Other Risk Management Processes. Of particular importance is the Integrity Management Program within the Operations and Maintenance category. Work completed in 2008 is discussed in the individual pipeline sections.

In accordance with PHMSA Regulations concerning *Pipeline Integrity Management in High Consequence Areas*, the Integrity Management Program (IMP) is designed to enhance and validate pipeline integrity. The program focus is to protect high consequence areas (HCA) from an unintended release of hazardous liquids from the pipeline system. CPAI reviews the *IMP* annually and revises sections as necessary and on June 10, 2008, the High Consequence Area identification was updated.

During the spring 2008, the PHMSA conducted an Integrity Management Inspection focusing on program implementation across all CPAI Pipelines. A follow-up meeting between CPAI and the PHMSA was held on July 24, 2008. CPAI reported no formal compliance actions from the PHMSA (as of December 2008). However, they reported that two compliance issues were discussed at the exit interview: 1) the qualification of individuals that review and evaluate assessment results and, 2) identifying and categorizing all information within 180 days of an inspection. CPAI reports that they have modified their procedures to address these issues.

The first issue was corrected by revising *5.11.04 Instrumented Pig Vendor Qualification and Documentation Guideline* to require personnel be qualified in accordance with API 1163, In-line Inspection Systems Qualification Standard, Section 5.2, Personnel Qualification. Three actions were taken by the Operator in relation to the second issue; 1) they secured required data from the ILI vendor and completed the required evaluation, 2) they revised *5.11.03 ILI Data-Gathering and Reporting Guideline* to establish and reinforce the reporting requirement guideline, and 3) they revised the Integrity Management Program, Section 5.7.3 Vendor Reporting Requirements and Section 5.8 CPAI Inspection Results Review to establish and reinforce the reporting requirement guideline

In support of Operations and Maintenance Risk Management CPAI conducts pre-job safety assessments, post-job reviews, routine safety meetings, maintenance and equipment integrity programs, insurance surveys, and TAP Root™ analysis. In addition to internal processes and programs, CPAI also utilizes PHMSA required programs including: the IMP, the Operator Qualification Program, the Public Awareness Program, and a Drug and Alcohol (Substance Abuse) Policy.

Safety Programs

Alaska Safety Handbook
CPAI uses a proactive approach to safety. It focuses on at risk behaviors. The Alaska Safety Handbook (ASH) defines standards of conduct and the responsibilities of contractors and CPAI employees that guide their day-to-day efforts on the job. CPAI expects all employees and contractors to understand and use the safety rules defined in the ASH. The ASH was last revised in 2006.

Contractor Programs
CPAI contractors implement their own plans and programs, which include health, safety, and environmental performance objectives and procedures that fall directly in line with CPAI's culture of safety.

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4.1.1 Alpine Pipelines

Figure 44. *A section of the Alpine Pipelines between CPF-2 and the Colville River.*

4.1.1.1 Right-of-Way Lease and Pipeline System Overview

Three pipelines, each approximately 34 miles long, connect the North Slope's westernmost development, Alpine, to infrastructure in the Kuparuk River Unit (KRU). The Alpine Oil Pipeline transports processed crude oil from the Alpine Central Facility (ACF) to the KRU Central Processing Facility 2 (CPF2). The Alpine Diesel Pipeline transports heating fuel and other petroleum products from CPF2 to ACF. The Alpine Utility Pipeline transports treated seawater from CPF2 to ACF for use in enhanced oil recovery.

For most of their length, the pipelines are aboveground. Specific physical characteristics of the Alpine Pipelines are provided in Appendix E, Physical Characteristics of SPCO Jurisdictional Pipelines.

ConocoPhillips Company (CPC) is the Lessee/Grantee for the three Alpine Pipelines. Alpine Transportation Company (ATC) is a general partnership between Alpine Pipeline Company (APC), Anadarko Alaska Pipeline Systems, Arctic Slope Regional Corporation, and Kuukpik Transportation Company. The ATC owns the Alpine Oil Pipeline. CPC owns the APC. CPAI owns the Alpine Utility Pipeline and the Alpine Diesel Pipeline. More information regarding ROW status and lease appraisal information can be found in Appendix H, Pipeline Right-of-Way Lease Appraisal Information. With the execution of the leases and grant on December 31, 2002, CPC became the Lease/Grant holder and is responsible for compliance with the ROW agreement requirements. Appendix G, Acreage, Survey, and Lease Information, contains additional lease information and Appendix F, Lease Required Contact Information**,** shows contact information required by each lease. ConocoPhillips Alaska Pipelines management and the SPCO maintain good communications and meet quarterly to discuss issues pertaining to the leases and grant, including updates on activities and plans related to all pipelines in which ConocoPhillips holds an interest.

4.1.1.2 Lessee's Annual Report

The report covered numerous topics including throughput, descriptions of the assurance programs, monitoring, leak detection, planned maintenance, unplanned events, and upcoming activities. The annual report was thorough and followed guidelines, as set forth in Appendix J (SPCO Annual Reporting Requirements for Lessees) of this report. Key elements of the annual report are summarized or excerpted below. Table 12 is a summary of throughput and pigging information for each of the Alpine pipelines.

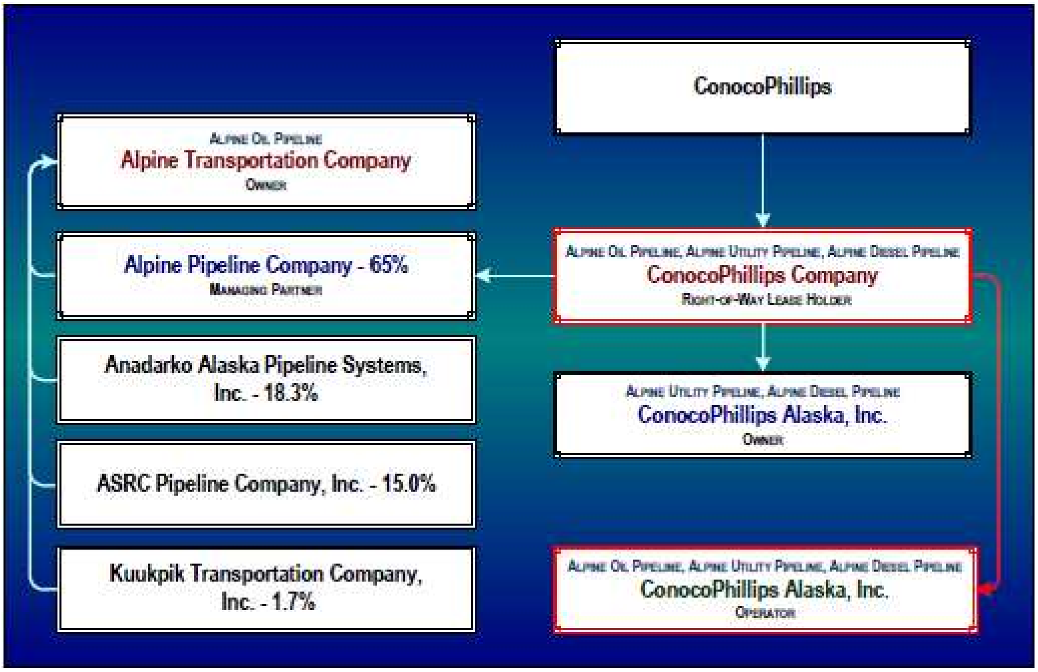

Figure 45. *Chart of Owner and Operator companies, provided by ConocoPhillips Company.*

<u>Pigging and Reliability</u>

The Alpine Oil Pipeline was 99.45% reliable in 2008. There were two planned and five unplanned shutdowns of the pipeline. It is important to note, however, that the all the shutdowns were due to external events and not the result of errors on the part of the pipeline operator. The unplanned shut downs occurred as follows:

1) April 29, 2008 unintended valve closure at TAPS Pump Station 1,
2) May 31, 2008 unintended valve closure during fire/gas preventative maintenance,
3) June 17, 2008 unintended valve closure due to faulty fire detect in AL03,
4) October 23, 2008 unintended valve closure due to faulty control card, and
5) November 20, 2008 unintended valve closure due to fouled vortex shedder meter.

In addition to the five unplanned shutdowns, Alpine Oil Pipeline took a proration (a reduction of their production rate) on October 10, 2008 due to high Valdez Tank

Inventory. Tank related work was being conducted at Kuparuk causing a lack of divert tank space; as a result, some production wells had to be shut in.

Table 12 shows pigging information for each of the Alpine pipelines.

Table 12. Pigging Information for the Alpine Pipelines, 2008.

Pipeline System	Maintenance Pigging	Last ILI	Pipeline Operator
Alpine Oil	11 times	2009	ConocoPhillips Alaska
Alpine Diesel	10 times	n/a (hydrostatic test in 2008)	ConocoPhillips Alaska
Alpine Utility	30 times	2009	ConocoPhillips Alaska

<u>Assurance Programs</u>

Health, Safety, and Environmental Management
In 2007, an Alaska Occupational Safety and Health (OSHA) team assessed the Alpine Voluntary Protection Program (VPP) and found Alpine to be consistent with a high quality VPP at the “Star” level. Because of this assessment Alpine will not need to be reassessed for 5 years, which is the maximum term allowed. There were no OSHA reportable conditions in 2008.

In 2008, there were 3,675 behavioral observations, 1,326 audits, near misses, or hazard identifications, and 5,001 proactive measures for the Alpine Development.

Operations Compliance Management Systems (OCMS)
Construction and Termination (Activities)
There were no construction or termination activities associated with the Alpine Pipelines in 2008.

Surveillance and Monitoring
The Alpine pipelines Surveillance and Monitoring Program, Edition 1, Rev 0 was approved by the SPCO on March 20, 2008. The CPAI SMP is designed to identify threats to personnel, safety, the environment, and pipeline integrity. The program combines numerous ground-based surveys with standard aerial surveys, and aerial surveys utilizing FLIR technology, which allows that detection of warmer temperatures and is useful in facilitating the identification of hydrocarbon releases, people, wildlife, or other entities that are warmer than background temperatures. The Lessee provided extensive summaries of these efforts in their annual report.

<u>Aerial Inspections</u>
In 2008, 140 aerial surveys of the ROW were completed, of these, 48 utilized FLIR technology. The goal is to conduct an aerial survey every 7-10 days on average. There were no "significant findings" that posed a threat to pipeline integrity.

Ground surveys

Ground inspections cover numerous elements of the operations. Items that are assessed include, but are not limited to, VSMs (tilting, settlement, frost-jacking, saddle movement), pipeline damage (dents, gouges etc.), pipeline insulation and jacketing, pipeline vibration and dampening, systems communication, corrosion control and cathodic protection mechanisms, dead legs, repair sleeves, leaks or spills, vegetation damage or rehabilitation, blockage of fish passage (low-water crossings, culverts), leak detection transmitters, bridge conditions, unauthorized construction, evidence of flooding or erosion, and valve condition (damage, leaks, indicators of functioning). There were no major findings that threatened pipeline integrity.

Risk Management

CPAI reviewed the Integrity Management Program (IMP) in 2008. The review resulted in revisions to many aspects of the program. Most changes were not significant. The most significant changes were made to the Inspection Plan. The changes included merging portions of the inspection and reassessment intervals and changes to the inspection planning process. Other small changes were made throughout. A focus was put on planning efforts, deadlines, and the requirement to address safety related conditions. CPAI updated the Integrity Management Program, Edition 2, Revision 0 on September 9, 2008.

CPAI also modified their Public Awareness Program in 2008. Revision 2 was issued in April 2008. The changes were primarily minor. Public awareness pamphlets were distributed in October, November, and December 2008.

CPAI has other Risk Management Processes, including, Process Safety Management, Employee Participation Plan, *Alpine Facility/Drillsite Emergency Action Plan* and Health, Safety, and Environmental Policies. No significant modifications were made to these programs.

Safety Programs

The Alaska Safety Handbook (ASH) was last revised in 2006. ConocoPhillips contractors also implement their own safety plans and programs.

Environmental Monitoring and Studies

The Annual Report provided information on wildlife observations, and long term monitoring reports. Field checks also included all stream crossings to confirm that there is no blockage to fish passage and to check for improperly screened water intake structures. Observations are made for bear dens and no bear dens were observed in 2008. Any fieldwork during denning season is coordinated with USFWS and ADF&G.

CPAI's *Data Report for Alpine Pipeline Caribou Surveys, 2008*, focused on distribution and movements of caribou in the area crossed by the Alpine Pipeline between the Colville River Delta and the Kuparuk CPF-2. A major issue associated with oil and gas development has been whether caribou movements in response to insects and weather will change or be limited by the presence of pipelines and other infrastructure. The surveys conducted in the Alpine field revealed no impediment to caribou movements, especially during insect season when some animals crossed the pipeline ROW more than once in the same day.

As part of the CPAI Pipeline Integrity Management Plan, Spectacled Eiders, listed by the USFWS as a threatened species, were also studied. This work is a continuation of pre-nesting Spectacled Eider surveys dating back to 1993 for the Kuparuk oilfield and expanded to include Alpine since 2004. The study includes pre-nesting aerial surveys looking at distribution, followed by ground surveys to identify nests. The report for 2008 was not complete at the time the annual report was submitted and will be reviewed next year.

Integrity Management

After the initial PHMSA 2008 Integrity Management Inspection completed March 2008 through April 2008, a follow-up meeting was held on July 24, 2008, regarding the Alpine Pipelines. No formal compliance actions were received from the PHMSA (as of December 2008) regarding the Alpine Pipelines themselves.

Maintenance

The annual pipeline ROW and river crossings surveillance was completed on December 21, 2008. Repairs from reportable conditions found in the 2007 surveillance were completed by May 7, 2008. A matrix of all maintenance completed for the pipelines in 2008 was included in the annual report.

Corrosion Control, Cathodic Protection, and Leak Detection

Corrosion control included the use of regular cleaning pigs (11 for the Alpine Oil Pipeline, 30 for the Alpine Utility Pipeline, and 4 for the Alpine Diesel Pipeline), installation and inspection of coupons, the use of corrosion inhibitors, in-line inspection to determine the extent of any corrosion, and pressure testing. Cathodic protection systems were tested to confirm functioning.

In addition, repairs were completed to the pig receiver on the Alpine Oil Pipeline. Maintenance pigging was able to resume after the plant restart in August.

Leak detection included system checks to confirm the proper functioning of sensors and transmitters. The functioning of the conduit and leak detection system under the Colville River was also checked. Testing showed a 1% volume imbalance was detected within 1 hour. New metering was installed at both ends of the Alpine Utility Pipeline in May 2008.

Discharges

On August 12, 2008 approximately 37-gallons of seawater, with trace amounts of hydrocarbons were spilled in the Alpine Pipelines rights-of-way during a scheduled Alpine Plant Shutdown. The spill was contained to the gravel pad and cleaned up. On August 25, 2008, there was a seawater spill in the Alpine Pipelines' rights-of-way. Approximately 75-gallons were spilled, 50-gallons to the pad and 25-gallons to secondary containment. The spill was contained to the pad and cleaned. The Alaska

Department of Environmental Conservation and the SPCO were properly notified of both spills.

The *Alpine Development Area Oil Discharge Prevention and Contingency Plan (ODPCP)* provides prevention strategies and response plans to limit the spread of a spill, minimizing potential environmental impacts, and to provide for the safety of personnel. This plan relies heavily upon information provided in the *Alaska Clean Seas (ACS) Technical Manua*l and identifies specific tactics descriptions, maps, and incident management information contained in the *ACS Technical Manua*l. CPAI conducted two spill drills in 2008 that involved staff from the Alpine IMT.

<u>2009 Plans</u>
CPAI completed In-Line Inspections on both the Alpine Oil and the Alpine Utility Pipelines in 2009.

4.1.1.3 Oversight Activities of the State Pipeline Coordinator's Office

(*This section provides a summary of SPCO activities. Information in this section reflects the work efforts of the State Pipeline Coordinator's Office and is not taken from the Lessee's annual report. By the nature of the SPCO work, there will be some overlap of information.)*

The SPCO compliance staff regularly conducts audits to assess compliance with the various elements of the different assurance programs. In the following summaries of the lessee's annual report, we discuss some of the work completed under the various program elements, subsets, of the Assurance programs that may be of particular interest to the public.

The Compliance Team reviewed the 2008 Annual Comprehensive Report on Pipeline Activities for Alpine Pipelines (ADL 415932, 415701, and 415857) and found it easily met the requirements of the lease.

On June 11-15, a Compliance Team Member traveled to Alpine to do on site observations of ILI completed on the Alpine Oil Pipeline and the Alpine Utility Pipeline and general ROW surveillance.

<u>In-Line Inspections</u>
Alpine Crude Oil Pipeline
SPCO Compliance staff observed both the launching and receiving of a smart pig in the Alpine Crude Oil Pipeline. All standard operating procedures were followed and the subsequent launching/receiving was a smooth process. 98% of data collected by the pig was recovered. CPAI deemed the ILI successful**.** Figure 46 depicts CPC specialists and contractors as they extracted and inspected a "smart pig" after the Alpine Oil ILI run on June 12, 2009.

Figure 46. *The pig receiver for the Alpine Oil Pipeline.*

Alpine Utility Pipeline

SPCO Compliance staff observed a successful launching and receiving of a smart pig in the Alpine Utility Pipeline. Upon retrieval of the pig, it was found that the data collection had not been successful. Two ILI pigs experienced major sensor failure for unknown reasons. The ILI specialists, however, managed to merge the data from both runs to obtain a complete set of data. The minimum allowable level for an ILI inspection under CPAI's procedures is 95% data recovery. The combined data for the two ILI runs achieved 97% data recovery.

<u>ROW Surveillance</u>

SPCO compliance team participated in an aerial surveillance of the Alpine ROW. Two groups of caribou were observed near the pipeline east of Alpine. Caribou were also observed at locations other than the allocated crossings. No tilting of VSMs along the pipeline route was noted. Connex containers containing emergency spill response tools were set in place along the pipeline.

SPCO Engineering Review: Alpine Oil and Utility Pipelines

Incidents of Note

The SPCO closely followed the response to the five unscheduled shutdowns, see section 4.2.2, related to Alpine's pipelines and facilities. None of the five events were caused by the pipeline operator. Pipeline pressure did not exceed the 110% reporting requirement for PHMSA during any of the shutdowns.

U-Bolt Replacement

Recently U-Bolt retrofits were completed on the Alpine Utility Pipeline. The operator retrofitted this line with Tyvar pads and added miscellaneous support improvements. Since then there has been one more U-Bolt failure that may have resulted due to cumulative strain over the past several years. Overall, the U-Bolt retrofit appeared successful. No other problems have been reported.

4.1.1.4 State Fire Marshall's Office

Annual Fire Prevention and Life Safety Inspections of the Alpine pipelines and related facilities were conducted by the Alaska Division of Fire and Life Safety on December 16, 2008. The inspections covered all process and production areas, man camp, support facilities, and CD2. The inspections successfully were conducted with the help of the ConocoPhillips Fire Marshal Liaison, Fire and Safety Personnel and Alpine Operations Personnel.

Nine violations were found during the inspection of the facilities at Alpine. None of the findings were under the authority of the pipeline operator. Many of those violations were corrected on the spot. There were no violations noted in the process areas or drill site CD2 demonstrating ConocoPhillips' commitment to fire and life safety issues at Alpine.

4.1.2 Kuparuk, Kuparuk Extension, and Oliktok Pipelines

Figure 47. *Lifting of the Kuparuk Pipeline Extension new pipe segment.*

4.1.2.1 Right of Way Lease and Pipeline System Overview

The 9.2 mile Kuparuk Pipeline Extension (KPE) begins at CPF2 and transports oil from both CPF2 and the Alpine Oil Pipeline to a connection manifold with the Kuparuk Pipeline at CPF1. The Kuparuk Pipeline then further transports processed crude oil from the KPE and CPF1, 28 miles eastward to TAPS PS 1. Additional oil enters the Kuparuk Pipeline approximately six miles downstream from CPF1 from the Milne Point Pipeline.

The Oliktok Pipeline (OPL) begins adjacent to the BP Operated Skid50 near PS 1. The OPL transports natural gas liquids from Prudhoe Bay to Kuparuk CPF1 to support operations. The Kuparuk Pipeline and the Oliktok Pipeline share the same horizontal and vertical supports between CPF1 and TAPS Pump Station 1.

The road systems in the Kuparuk Unit and Western Prudhoe Bay provide year-round access to the Kuparuk production facilities. Access roads are also available along the ROW itself with the exception of the river crossings. The Kuparuk Pipeline and Oliktok Pipeline cross the Kuparuk River floodplain and various tributaries as well as Central Milne Creek, East Creek, Sakonowyak River, and the Putuligayak River. The Kuparuk Pipeline Extension crosses the Ugnuravik River and a minor unnamed drainage. All three pipelines are located above ground except at caribou and road crossings where they have been placed below grade within casings, which provide an annulus of air and galvanic isolation.

The “original” 16-inch Kuparuk Pipeline, laid in 1981, carried processed crude oil to PS 1. Later that same year, the Kuparuk Pipeline Extension was constructed from CPF-2 to CPF-1, and was comprised of both 12 and 18-inch segments. In 1984, when the new 24-inch Kuparuk Pipeline was laid, the "original" Kuparuk Pipeline was converted to the Oliktok Pipeline, which now carries natural gas liquids from PS 1 (Skid-50) back to CPF-1. The KPE was also placed in service at this time and connected to the 24-inch KPL. In 2009, as part of the smart pigging project, the 12-inch segment of the Kuparuk Pipeline Extension was replaced with 18-inch pipe, which will make that portion of the pipeline piggable. Specific physical characteristics of the pipeline are provided in Appendix E, Physical Characteristics of SPCO Jurisdictional Pipelines.

All three of these pipeline rights-of-way are in operational width, typically 150 feet. Although the KPL and OPL share supports, they have separate ROW leases. The KPL Lease was amended in 2004 to place a pig launcher shelter near CPF-1. As part of the ongoing activities related to the KPE smart pigging project, a pig launcher and receiver will be installed to provide pigging capabilities along the 18-inch stretch of pipe. (Anticipated completion is in 2010.) Additional lease information can be found in Appendix G, Acreage, Survey, and Lease Information.

The Kuparuk Transportation Company (KTC) is the Lessee for the KPL and the KPE. KTC is a general partnership between Kuparuk Pipeline Company (owned by CPC), BP Transportations (Alaska), Inc. (BPTA) and Union Kuparuk Pipeline Company (Appendix F, Lease Required Contact Information). The Lessee for the Oliktok Pipeline is Oliktok Pipeline Company, which is wholly owned by CPC. Figures 48 and 49 offer a visual display of the above information, and were provided in the lessee's annual reports.

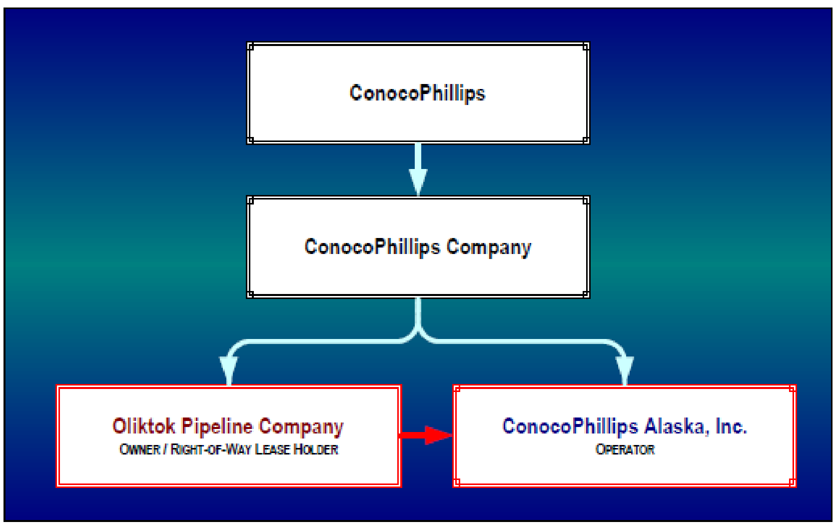

Figure 48. ***Oliktok, Owner and Operator Company information.***

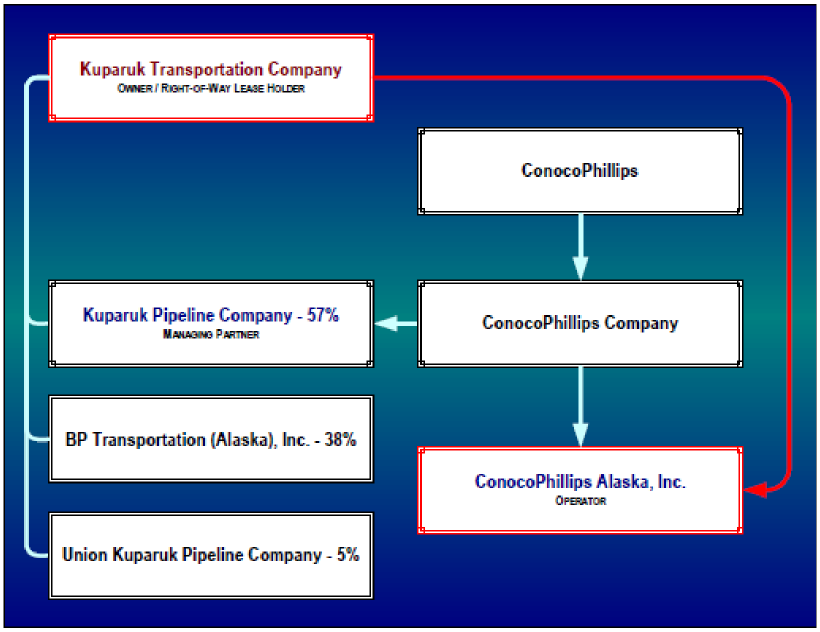

Figure 49. *Kuparuk, Owner and Operator Company information.*

4.1.2.2 Lessee's Annual Report

KTC submitted their annual report for the KPL and KPE on January 30, 2009. The Oliktok Pipeline Company also submitted their annual report for the OPL on January 30, 2009. Both reports met SPCO expectations, as set forth in Appendix J, SPCO Annual Reporting Requirements for Lessees. The overall quality of the reports was very good.

The lessees, the operator, and the SPCO maintain open communications and meet each quarter to discuss issues pertaining to the leases. The meetings cover six pipelines under SPCO jurisdiction that are operated by ConocoPhillips Alaska, Inc.

Pigging and Reliability

All three of the pipelines were 100% reliable in 2008. Table 13 shows pigging information for the Kuparuk Pipeline, the Kuparuk Pipeline Extension, and the Oliktok Pipeline. Changes to the KPE, replacement of the unpiggable section and the addition of a pig launcher and receiver, are discussed in the SPCO Activity Section of this report.

Table 13. Pigging Information for Kuparuk and Oliktok Pipelines, 2008.

Pipeline System	Maintenance Pigging	Last ILI	Pipeline Operator
Kuparuk Pipeline	Monthly	2009	CPAI
Kuparuk Pipeline Extension	Sections unpiggable	Sections unpiggable	CPAI
Oliktok Pipeline	No current pigging facilities	No current pigging facilities	CPAI

Assurance Programs

Health, Safety, and Environmental Management
ConocoPhillips Alaska, Inc. uses a "proactive measures" approach to safety. It focuses on at risk behaviors. In 2008, there were 2,883 behavioral observations, 1,636 audits, near misses, or hazard identifications, and 4,519 proactive measures for the Kuparuk and Oliktok Development areas.

On August 4, 2006 the Greater Kuparuk Area Process Safety Management Employee Participation Plan and Roadmap was issued, this plan covers the Kuparuk, Kuparuk Extension, and Oliktok Pipelines and includes near miss reporting, the Behavior Eliminates All Risk (BEAR) Process, the ASH revision process, compliance safety audits, monthly incident review meetings, as well as other processes and programs.

Risk Management
Process Hazard Analysis, a segment of risk management for Design and Construction were revised in 2008. CPAI conducted a process hazard analysis to identify potential health and safety hazards associated with the Kuparuk Pipeline Extension upgrade project. A Process Hazard Analysis is a segment of risk management for Design and Construction.

Emergency Management and Response for the Kuparuk, Kuparuk Extension, and Oliktok Pipelines are covered under the Greater Kuparuk Area Facility/Drillsite Emergency Action Plan, which was last revised September 17, 2007.

Environmental Monitoring and Studies
The Annual Report provided information on wildlife observations, and long term monitoring reports. Field checks also included all stream crossings to confirm that there is no blockage to fish passage and to check for improperly screened water intake structures. Observations are also made for bear dens.

CPAI submitted executive summaries for *Mammal Surveys in the Greater Kuparuk Area, Northern Alaska, 2007,* and *Mammal Surveys in the Greater Kuparuk Area, Northern Alaska, 2008.* The focus of these field efforts was on recording data on distribution, abundance, and calf production of the Central Arctic Herd (CAH) caribou between the Colville and Kuparuk Rivers. In 2007, calf production was estimated at 73.9 calves:100 cows. In 2008, it was estimated at 78.3 Calves:100 cows. Calf production for both years exceeds the mean annual production of 73.2 calves:100 cows. This has been true for 12 of the first 13 years.

Several large groups of Muskoxen were observed both years. There were 17 sightings in 2007 and 28 in 2008. There were a greater percentage of calves observed in 2008 than 2007. In 2007 there were 16 grizzly bear sightings totaling 18 adults and 11 cubs. In 2008, the number of brown bear sightings increased to 20 adults and 16 cubs. All of these sightings were within 75 km of the coast in the National Petroleum Reserve, Alaska and Kuparuk-Colville River regions. Besides the Brown bear sightings, there were five polar bear sightings (totaling 5 adults and 4 cubs) in 2007 and one polar bear sighting on the Colville River delta in 2008

ConocoPhillips Alaska, and its predecessor, ARCO Alaska, have been conducting avian studies in the Kuparuk Oilfield since 1985. Their current work focuses on three key species, the Spectacled Eider, Tundra Swan, and Brant. Spectacled Eiders were listed by the US Fish and Wildlife Service as a threatened species in 1993. Since that time ConocoPhillips has been collecting pre-nesting data on the Spectacled Eider for the Kuparuk oilfield and expanded to include Alpine since 2004. The study includes pre-nesting aerial surveys looking at population trends, distribution, identification of important nesting habitats and nesting success, all relative to the oil and gas infrastructure. The report for 2008 was not complete at the time CPAI's annual report was submitted and will be reviewed next year, but the 2007 report was included. Both the number of Spectacled Eiders and their nesting success were down in 2007. It is notable however that 2007 was a colder than average spring, and that snow persisted into late May. While Steller's Eiders were not the subject of the study because they breed mainly in western and northwestern Alaska, it was nice to learn that two pairs were observed resting in the Kuparuk study area.

In contrast to the Spectacled Eiders, the density of Tundra Swans, monitored because they are considered a good indicator of the overall health of water bird populations, was 29% higher that the long-term mean in the Kuparuk Oilfield. This shows a significantly increasing population. The Brant studies showed an increase in the adult population and a decrease in the gosling population. If one discounts the no- or failed-breeding adults, the percentage of goslings for brood rearing groups increased by 31%.

<u>Integrity Management</u>
After the initial PHMSA 2008 Integrity Management Inspection, a follow-up meeting on July 24, 2008, of the Kuparuk and Kuparuk Extension Pipelines was made. No formal compliance actions were received from the PHMSA (as of December 2008) regarding the Kuparuk and Kuparuk Extension Pipelines themselves.

The Oliktok Pipeline was inspected by a PHMSA representative as well in July 2008. As a result of the inspection, the PHMSA transmitted a Notice of Amendment (CPF 5-2008-5029M) and a Warning Letter (CPF 5-2008-5030W) to communicate compliance actions. The Notice of Amendment addressed Maintenance and Normal Operation – Purging a permanently abandoned line, Abnormal Operation – Starting a pipeline after purging, and Pipeline Repairs – Outdated American Petroleum Institute reference. PHMSA approved a response extension on October 14, 2008 to allow Oliktok Pipeline Company additional time to develop and/or revise procedures. On December 9, 2008 Oliktok Pipeline Company addressed the Notice of Amendment by transmitting the revised procedures required for PHMSA consideration. The Warning Letter addressed Valves – Position indicators. CPAI took corrective action, as required, by replacing the original dust covers with a metal mesh enclosure marked so the position of the valve was easily visible.

Maintenance
The State Pipeline Coordinator's Office and ConocoPhillips met on February 19, 2008 to discuss the proposed replacement of the 12-inch section of the Kuparuk Pipeline Extension. This project will replace a 12-inch diameter section of the Kuparuk Pipeline Extension from CPF-2 to DS-2Z with 18-inch diameter pipe, enabling the pipe to be

pigged in the future. Engineering, planning, and permit applications were the focus of the project in 2008. The pipe replacement itself will take place in 2009.

On August 24, 2008, KTC notified the SPCO, in compliance with lease stipulation 1.13.1, that primary monument D-12 was accidentally destroyed during casing excavations on the Spine Road at the Oliktok Road intersection in the Kuparuk Pipeline Extension ROW. The excavations did not involve the KPE. The monument was replaced by the contractor that conducted the annual Kuparuk Pipeline Extension ROW monument inspection.

During routine inspection for external corrosion of field applied weldpacks, an area of localized corrosion was identified at VSM 1218 on September 11, 2008. The SPCO was notified of the condition and the corrective actions taken on September 12, 2008. A full-rated welded sleeve was installed at VSM 1218 on December 19, 2009 for the KPL under work order 5629810, VSM 1820 received a sleeve under work order 5593806 on December 14, 2008.

Surveillance and Monitoring

The CPAI SMP is designed to identify threats to personnel, safety, the environment, and pipeline integrity. The program combines numerous ground-based surveys with standard aerial surveys, and aerial surveys utilizing FLIR technology, which allows that detection of warmer temperatures and is useful in facilitating the identification of hydrocarbon releases, people, wildlife, or other entities that are warmer than background temperatures. The Lessee provided extensive summaries of these efforts in their annual report.

Aerial Inspections

During 2008, 95 aerial surveys were conducted between CPF-1 and PS1on the Kuparuk and Oliktok Lines, 51 of which used FLIR technology. Another 117 were conducted in the Kuparuk field between CPF-1 and CPF-2, of which 51 used FLIR technology. There were no significant findings that posed a threat to pipeline integrity.

Ground surveys

Ground inspections cover numerous elements of the operations. Items that are assessed include, but are not limited to, VSMs (tilting, settlement, frost-jacking, saddle movement), pipeline damage (dents, gouges etc.), pipeline insulation and jacketing, pipeline vibration and dampening, systems communication, corrosion control and cathodic protection mechanisms, dead legs, repair sleeves, leaks or spills, vegetation damage or rehabilitation, blockage of fish passage (low-water crossings, culverts), leak detection transmitters, bridge conditions, unauthorized construction, evidence of flooding or erosion, and valve condition (damage, leaks, indicators of improper functioning). There were no major findings that threatened pipeline integrity.

<u>Discharges</u>

There were no discharges associated with the pipeline system or ROW in 2008 for the KPL, KPE, or OPL.

The *Kuparuk River Unit Oil Discharge Prevention and Contingency Plan (ODPCP)* provides prevention strategies and response plans to limit the spread of a spill, minimizing potential environmental impacts, and to provide for the safety of personnel. This plan relies heavily upon information provided in the *ACS Technical Manua*l and identifies specific tactics descriptions, maps, and incident management information contained in the *ACS Technical Manua*l. CPAI reviewed and incorporated revisions in May, June, July, August, and October 2008. The ODPCP expires May 2, 2013.
CPAI participated in two spill drills in 2008 that involved staff from Kuparuk River Unit. The first drill was the North Slope Mad Exercise conducted on April 2, 2008. This was followed by a Kuparuk Spill Response Team and IMT tabletop exercise on September 29, 2008 and October 10, 2008.

<u>2009 Plans</u>
CPAI received materials for a project to complete the upgrade of the 24-inch pig launcher and receiver valves by second quarter 2009. This project will enhance safety when performing routine maintenance pigging. At the time of the writing of the 2008 annual report CPAI was in the process of installing pig launcher and receiver sump pumps and was also in the process of replacing the fast loop sampler.

CPAI received materials and was in the process of completing the upgrade of the existing flow computer to address obsolescence and issues with availability of parts. The new computer will also provide more accurate and reliable information. The computers at CPF-2 were being worked on in 2008 and those at CPF-1 were scheduled for installation in the second quarter of 2009.

A Greater Kuparuk Area *Health, Safety and Environment Self-Audit* is scheduled in 2009 and will be followed by a Greater Kuparuk Area Health, Safety and Environment Corporate Compliance Audit in 2010.

In 2009, CPAI plans to complete or continue working on the some system modifications and improvements. Upgrades will be made to both the hardware and software for the leak detection system (this has been an ongoing project for CPAI). Replacement of a Bailey Bridge was scheduled for completion in April 2009, but it has been postponed to 2010. The structural steel components were fabricated and decking installed. The unit was shipped to Fairbanks. The final work plan called for the removal of the existing bridge and piles, drill & slurry new piles, pile cap and abutment work and the setting of bridge.

4.1.2.3 Oversight Activities of the State Pipeline Coordinator's Office

(*This section provides a summary of SPCO activities. Information in this section reflects the work efforts of the State Pipeline Coordinator's Office and is not taken from the Lessee's annual report. By the nature of the SPCO work, there will be some overlap of information.)*

<u>SPCO Compliance Section:</u>
SPCO staff traveled to the field and inspected the Kuparuk, Kuparuk Extension, and Oliktok rights-of-way one time as part of a consolidated field trip to view multiple pipelines. (A list of all surveillance reports is included in Appendix I.)

Tour of the Kuparuk, Oliktok, and Kuparuk Extension ROWs and Related Facilities
SPCO staff joined KTC staff on a tour of the pipeline ROW, starting at the pig receiver just outside TAPS PS 1, and continuing along most of the length of the ROW to the pig launcher at the CPF-1. During this trip, SPCO staff noted a shoe off of the HSM and broken banding due to ice jacking of a vertical support member (Figure 50). The damage had previously been identified for repair by the operator. SPCO staff noted geese and caribou on both sides of the pipeline during this trip.

Figure 50. *Kuparuk and Oliktok Pipelines, shoe off of supports, August 2008.*

Bridge to be Replaced, Kuparuk, and Oliktok ROW

Figure 51. *Kuparuk Pipeline (and Bailey Bridge) crossing Smith Creek.*

A planned replacement of the Bailey Bridge crossing over Smith Creek (Figure 51) was deferred by KTC. Although an ice road was built and snow removal occurred at the site and was observed by the SPCO on the February 2009 trip, no other activities were observed for this project and the Regulatory Compliance Coordinator indicated that the project had been deferred.

SPCO Field Trips, Kuparuk Pipeline Extension

The SPCO Compliance Section traveled to the North Slope and observed the KPE three times during FY09. These trips resulted in surveillance and field reports addressing the Kuparuk Pipeline Extension Smart Pigging Project, pipe replacement activities, and general right-of-way lease conditions.

August 28, 2008, SPCO compliance staff made a trip to observe many of the jurisdictional pipelines on the North Slope. Surveillance reports addressed SPCO staff access to facilities and along the pipeline, and the conduct of safety briefings. Two additional trips, February 9, 2009 and March 11, 2009, were taken to observe activities related to the Smart Pigging Project. This was a project to replace the existing 12-inch diameter segment with an 18-inch diameter segment of pipe, and then install pigging facilities to enable pigging of the entire Kuparuk Pipeline Extension. A summary of all Surveillances Reports can be found in Appendix I, SPCO Surveillance Reports Issued in FY09, and are described below in detail.

Kuparuk Pipeline Extension - Pipe Replacement
The two field trips to KPE taken during FY09 were made during different stages of the pipe replacement project. On February 9, 2009, to the SPCO compliance representatives observed activities during the removal of previously abandoned pipe from the rack. The pipe was removed to create a place for the new 18-inch Kuparuk Pipeline Extension pipe (Figure 52). Conditions on the North Slope during the trip were very cold (minus 40 degrees Fahrenheit) and a stop work order was in place for hydraulic equipment. Hydraulic equipment was staged and ready to move, and project staff were in continuous communication on work conditions. Although, pipe lifts were at a standstill, the SPCO staff was able to observe the status of pipe removal, the pipe cleaning bay, delivery of pipe segments and staged project materials.

Figure 52. *Old 12-inch KPE pipe removed from the rack leaving space for the new 18-inch pipe to be installed.*

SPCO compliance staff also reviewed the project Construction/Installation Readiness checklist, pipe lift, cold cut plans, permit documents, and spill records. In response to equipment fluid spills (none on the ROW), the operator instituted additional equipment inspection requirements to identify potential issues and prevent future spills. SPCO staff attended the morning safety meeting where these procedures and the associated checklist styled form were reviewed and emphasized. In addition, the discussion included recent work activities with a lessons learned approach.

Five surveillances and a field report were issued related to the February trip, all of which yielded satisfactory results.

On March 11, 2009, SPCO compliance staff observed the placement of the new pipe segment onto the pipe rack. Even with Phase 1 and 2 weather conditions, the SPCO was able to observe pipe lift activities that were executed with deliberation and care. Access to the ice road and proximity to the working area were controlled, and the lift went smoothly.

The March trip resulted in five satisfactory surveillances, and a field report. Oil started flowing through the new 18-inch KPE pipe on July 4, 2009.

Snow Removal Incident
On March 11, 2009 an incident occurred (not observed by SPCO), where an excavator being used for snow removal encountered a nearby gas pipeline, peeling back the pipe jacket (Figure 53).

Figure 53. *Jacket damage to a pipe* ***adjacent to*** *Kuparuk from snow excavation incident.*

The incident occurred at the road crossing near the CPF-2 pad. The project manager responded immediately by stopping all snow removal work, then instituting a non-mechanical requirement for snow removal, as well as, initiating a root cause analysis of the incident. The findings pointed to a failure to follow Snow Removal and Excavation, Trenching, and Drilling standards as defined by the 2006 Alaska Safety Handbook for work close to pipelines.

<u>SPCO Right-of-Way and Permits Section Activities</u>:
Lease Amendment for Pipe Replacement Project:
On August 26, 2008, the SPCO received a letter from KTC requesting an amendment to the KPE Right-of-Way Lease, ADL 409027. The purpose of the lease amendment was to allow both the replacement of the 12-inch portion of the pipeline between CPF-2 and Drill Site 2Z with 18-inch pipe and the inclusion of a pig launcher on the CPF-2 pad and a pig receiver on the CPF-1 pad. Following public notice, a 60 day comment period and a coastal zone consistency review, a final consistency determination was issued that concurred with the applicant that the project is consistent with the ACMP and the affected coastal district's enforceable policies. A second public notice was followed by a thirty-day public comment period. On January 8, 2009, the DNR Commissioner signed the lease amendment documents to add the land needed for the pig launcher and receiver

areas to the pipeline ROW, encompassing 0.0435 acres, more or less. The lease amendment was later recorded in the Barrow Recording District as Document 2009-000238-0.

Pipeline Replacement Project Authorization:
On November 28, 2008, the SPCO sent a letter (.) to KTC with conditional authorization under Stipulation 1.7.1 of the ROW lease, ADL 409027, to begin construction of the new 18-inch diameter pipeline. The pipeline replacement project will be conducted within the existing Kuparuk Pipeline Extension ROW for approximately 4.15 miles. The letter indicated that the SPCO had reviewed the final version of the "Kuparuk Pipeline Extension (KPE) Smart Pigging Project, Design Basis" dated October 13, 2008, and determined it to be sufficient and acceptable.

SPCO Engineering Review:
Kuparuk Pipeline and Kuparuk Pipeline Extension
The Bailey Bridge replacement project has been delayed until 2010-2011. CPAI had an independent engineering firm inspect the old bridge and approve it for continued use.

The largest change to the system was the replacement of the upper half of the KPE. Previously this was a dual-diameter pipeline with the first half of the line having a 12-inch diameter and the second half having an 18-inch diameter. The replacement resulted in a single 18-inch pipeline.

The pipeline portion was mechanically complete and hydrostatically tested in June 2009. The new KPE line was filled on July 4, 2009. The abandoned KPE pipeline section was de-inventoried and decommissioned. APSC has been integrated into the planning and Process Hazard Analysis for the KPE de-inventory project due to the sensitivity of these type operations following the January 15, 2009 BP incident at PS 1, which occurred while decommissioning some of the transit lines in Prudhoe Bay.

The constant diameter will allow the KPE to be smart pigged once permanent pigging modules with pig launcher and receiving capabilities are complete. At the end of this reporting period, the Process Hazards Analysis for the KPE Pigging Modules is done. The engineering of these modules is complete and the pig-module fabrication contract is taking place. In addition, during the July 18-19 shutdown, the valves for the pigging modules were installed at CPF-1. The pig modules are currently planned to be installed second quarter of CY10. The first ILI run is scheduled for the third quarter of CY10.

One change to the KPL has been announced. The pipeline operator has plans to replace a buried section of pipe inside the PS 1 perimeter. This will aid inspections.

Oliktok Pipeline
The OPL transports NGL from Prudhoe Bay westward to the KRU. It was originally commissioned as the oil transport pipeline from CPF-1 to PS 1 in 1981. It was converted to fuel gas service in 1985 and decommissioned in 1988. It was then converted to natural gas liquid transport in December 1995. The SPCO received no indications of major incidents or events on the pipeline.

A project investigating the potential for future line usage and pigging of the pipeline is under consideration. If it were to come to fruition, smart pigging would be scheduled to be performed in the third quarter of CY10.

4.1.2.4 State Fire Marshal's Office

October 27-31, 2008

Annual Fire Prevention and Life Safety Inspections of the Kuparuk Extension and related facilities and Oliktok pipeline related facilities were conducted by the SFMO on October 27-31, 2008. There were 16 minor violations found during the inspection of Kuparuk process facilities. There were 14 minor violations found in non-process facilities. None of the findings were under the authority of the pipeline operator. Most the violations were either corrected on the spot or put on work orders or preventative maintenance (PM).

March 17-19, 2009

The 2009 Annual Fire Prevention and Life Safety Inspections of the Kuparuk and Oliktok facilities were conducted by the Alaska Division of Fire and Life Safety Inspection on March 17-19, 2009. Inspections covered the Seawater Treatment Plant, KCS Pad, in addition to various living quarters and office space.

Four violations were found during the inspection of the Seawater Treatment Plant at Oliktok Point. 16 violations were found at the Kuparuk Central Services pad (industrial shops and maintenance buildings). There were 13 violations found in the Kuparuk Operations Center living quarters. None of the findings were under the authority of the pipeline operator. Many of those violations were minor and were either corrected on the spot, or put on work orders or preventative maintenance. In his inspections, the State Fire Marshal observed fewer repeat corrections needed, and noted that this indicated a genuine effort to make facilities at Kuparuk a fire safe workplace. The State Fire Marshal also expressed appreciation for a fire drill that was executed for the benefit of the State Fire Marshal during his inspection at Kuparuk.

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4.2 BP Transportation (Alaska), Inc. (BPTA)

BP Assurance Programs

BPXA, as pipeline operator for the Lessee, BPTA, implements a number of assurance programs company-wide. The programs have been developed by the Lessee's and pipeline operator to govern operational and maintenance activities in a manner that recognizes and addresses personnel safety, environmental protection, maintaining the integrity of the infrastructure and providing adequate preparation for response to unanticipated events. This section of the SPCO Annual Report provides a high-level overview of the Quality Assurance Program, the Safety Programs, the Integrity Management Program, and other Risk programs, as reported in each Lessee's 2008 Annual Report. It is worth noting that all of the BPXA AS 38.35 pipelines come under the authority of the PHMSA with respect to pipeline integrity. PHMSA is a partner agency within the JPO.

The general purpose and structure of the BPTA and BPXA assurance programs are described in this section. The following sections are pipeline specific and give an overview of each line, production rates, activities that illustrate compliance to the assurance programs, and other highlights of CY08 BPTA. At the end of each section there is a summary of SPCO efforts related to each pipeline.

Quality Assurance Program

The comprehensive QAP is required by respective lease stipulations, and other regulations. The goal of the BPTA program was approved by the SPCO on December 21, 2004 is intended to protect the health and safety of people, as well as protect the environment and integrity of the pipeline and other facilities. Elements of the QAP include leadership and accountability, risk assessment and management, training, operator qualifications, contract accountable managers, third party assessments, compliance and obligation tracking, detailing all operating procedures, community awareness, crisis and emergency management, incident investigation, corrective and preventative actions and assessments and improvements.

BPTA uses planned, systematic processes, including internal and external audits, to evaluate and document achievement of QAP requirements, including compliance with lease stipulations and PHMSA requirements. The QAP applies to all of the BPTA pipelines and provides continuity across the BPTA leases.

The BPXA GIS (Atlas) program became available in December 2008. It includes comprehensive spatial information, including high resolution photography and maps. It details, among other things, pipelines, roads, pads, facilities, and land ownership. It provides an extremely useful tool to BP pipelines and will be valuable to many projects including work done under the QAP.

Personnel Safety Programs

In addition to the standard safety programs that govern procedures and processes, BPXA has instituted a program aimed at increasing safety awareness among individuals and within the community. It is an effort aimed at reducing incidents attributable to human error. Each development area takes ownership of its own version of this program that has both an internal and external component.

The internal safety program is a form of peer monitoring. Employees formally monitor each other's safety behavior. They record observations and include suggestions for potentially unsafe behavior and positive reinforcement when they observe and note good practices. The effectiveness of the program is demonstrated by the improving safety statistics for each field, which are detailed by oilfield in this report.

The external safety program focuses on contractor safety. Contractors working in a given oilfield actively participate in the internal safety program. Additional controls that apply to contractors under the external program focus on giving accountability for contractor activity to BPXA supervisors. Contractors must receive an *Authorization to Proceed* from a BPXA supervisor, and when appropriate, perform a *Task Hazard Analyses*.

<u>DOT Integrity Management Program</u>
USDOT issued an amendment to 49 CFR Part 195.452, on December 1, 2000. This led to a final rule in 2002 implementing a pipeline integrity management program for all hazardous liquid pipeline operators. Initially, the program only applied to the six-mile sub-sea segment of the Northstar oil pipeline. In 2006, the program was extended to cover the remainder of the Northstar oil pipeline and the other AS 38.35 jurisdictional pipelines, Badami, Endicott and Milne Point pipelines. On May 20 and 22, 2008 a formal risk assessment of BPTA lines was conducted. The assessment is structured to identify those things that have the potential to directly impact the integrity of the pipeline. A key output of the assessment is the identification of preventative and mitigative measures (P&Ms). These measures, when implemented, prevent and/or mitigate the likelihood of a pipeline failure that could affect a High Consequence Areas as defined by 49 CFR 195.452. The risk assessment also reviews all P&Ms that were developed in previous years. This year the risk assessment, which covered all the BPXA pipelines (including the 38.35 pipelines), identified two new P&M measures: 1) Hire four slope based DOT Coordinators by end 3Q 2008 and, 2) Develop business resumption plans by end 4Q 2008 for Northstar subsea portion of the pipeline system, and new OTLs (in-field lines, not 38.35 pipelines) in the Greater Prudhoe Bay Area (GPB).

<u>Corrosion Program</u>
The internal corrosion program is divided into four elements: 1) Corrosion Rate Monitoring, 2) Erosion Rate Monitoring, 3) Frequent Inspection Program, and 4) the Comprehensive Integrity Program. The external corrosion program is less systematic because external corrosion is more random. External corrosion is primarily associated with water absorption by the thermal insulation that surrounds the pipelines. Particular areas of concern include the weld packs, which surround the welds made during construction and therefore must be field-applied. Corrosion prevention inspections, such as ultrasonic external inspections and ILI runs, are included in the Operator's surveillance and monitoring efforts.

Other Risk Management Programs

In addition to the programs described above and the PHMSA required risk assessments, BPXA has other risk management programs. These programs also address health, safety and environmental issues as well as pipeline integrity concerns. Several that are significant in terms of operating the AS 38.35 pipelines are described here.

DEC-approved Oil Discharge Prevention and Contingency Plans include identification of potential risks along the pipeline rights-of-way, preventative measures, communication protocols, and pre-staging of response equipment.

A USDOT Pipeline Operator Qualification program ensures that personnel have the appropriate training, knowledge, and skills to safely perform their assigned tasks and can recognize and respond to abnormal situations. This program includes a tracking system to monitor training and qualifications. BP project managers can verify and review contractor qualifications before and during a project.

BPXA has a Health, Safety and Environment (HSE) Management System under which environmental risks are ranked annually including activities on the pipeline rights-of-way. Any activity determined to be high risk is evaluated to ensure that the planned protective measures in place are sufficient. This management system is certified annually by an ISO 14001 Registered Firm.

The USDOT Public Awareness/Damage Prevention Program is targeted to stakeholders who can affect the operations or integrity of one of their pipelines. The primary focus is education. A brochure that addresses pipeline safety receives wide distribution. In 2008 pipeline and facility descriptions, and contact information were all updated.

Surveillance and Monitoring

The SMP involves visual inspections of the pipelines specifically looking at all elements of the structure and the surrounding area so that any abnormal situation or unexpected change is detected and evaluated before it can cause a problem. The goal is to prevent situations that threaten health, safety, the environment, or pipeline integrity. Surveillances are primarily qualitative observations of surface conditions. Both ground (drive-by and walking) and aerial (visual and FLIR detection) access is used to perform surveillances. Any indication of a problem, unexpected condition, or leak is reported immediately. After evaluation, the appropriate action is taken to correct or mitigate the situation. In addition to PHMSA required surveillances, each pipeline receives an annual walking speed survey that provides for a detailed ground-level inspection of the pipeline.

USDOT surveillance requirements, 49 CFR 195.412(a), requires that surface conditions on or adjacent to each hazardous liquid pipeline ROW be inspected at intervals not exceeding three weeks, but at least 26 times each calendar year. During these surveys, any changed or unusual condition on or adjacent to each pipeline is noted. PHMSA also requires follow up as appropriate. There are some conditions or environmental changes that do not require immediate action, but they continue to be monitored. Monitoring is based on the acquisition and evaluation of quantitative data over time. It is used to identify trends and unexpected or cumulative changes before they pose a threat to safety, the environment or pipeline integrity.

Pipeline Specific Information

The SPCO compliance staff regularly conducts audits to assess the lessee's compliance with the various elements of the different assurance programs. They also review annual reports provided by the pipeline operators detailing work each year. The reports address general operational updates as well as work specific to the Assurance programs. In the following sections, organized by pipeline, you will find summaries of FY08 work completed under different elements of the assurance programs that may be of particular interest to the public, as well as a brief description of other activities related to operations, or unplanned events.

4.2.1 Badami Sales Oil and Utility Pipelines

Figure 54. *Pigging facilities near the Badami Sales Oil Pipeline tie-in to the Endicott Pipeline.*

4.2.1.1 Right-of-Way Lease and Pipeline System Overview

The Badami Pipelines connect the North Slope's easternmost oil development, Badami Oil Field, to the Endicott Pipeline. The 12-inch Badami Sales Oil Pipeline begins at the Badami Central Production Facility, where the pig launcher, mainline pumps, and metering equipment are located (Appendix E, Physical Characteristics of SPCO Jurisdictional Pipelines). It ends approximately 25 miles to the west at the tie-in with the Endicott Pipeline, where there is a pig receiver (Figure 54).

The 6-inch Badami Utility Pipeline begins at the "T" intersection on the Endicott causeway where it tied into the fuel gas line that transports miscible injectant from the Main Production Island (MPI) to the Satellite Drilling Island (SDI). It was designed to transport miscible injectant from MPI to the Badami Central Production Facility, approximately 31 miles. It operated intermittently to supply fuel gas for start up of the Badami facility and operated briefly in August 2007 to supply gas to push an ILI tool through the Badami Oil Pipeline. It was disconnected from the Endicott Pipeline and is not currently operating. Both pipelines are aboveground, except at the major river crossings of the Shaviovik, Kadleroshilik, and Sagavanirktok Rivers.

The ROWs for both pipelines were in construction-width status during FY08. The Badami Sales Oil Pipeline has a construction width of 300 feet, except at the buried river crossings where the ROW expands to 2,000 feet. The Badami Utility Pipeline has a construction width of five feet between the Endicott tie-in and the Badami Central Production Facility and an expanded width of 300 feet between the Endicott tie-in and the MPI. Construction of the Badami Utility Pipeline took place within the ROW of the Sales Oil Pipeline.

The leases for both pipelines were executed on December 15, 1997 and are set to expire on December 14, 2022 (Appendix G, Acreage, Survey, and Lease information).

4.2.1.2 Annual Report

BPTA submitted its annual report to the SPCO on February 4, 2009, which presented information for seven pipelines, including the Badami Pipelines. The report format paralleled the SPCO reporting requirements and met SPCO expectations, as set forth in Appendix J (SPCO Annual Reporting Requirements for Lessees) of this report. BPTA and the SPCO maintain good communications and meet quarterly to discuss issues pertaining to the lease, including BPTA updates on activities and plans related to all BPTA pipelines (Appendix F, Lease Required Contact Information).

Significant items excerpted and extracted from the BPTA Annual Report regarding these Badami pipelines are presented below.

Operations - Throughput Pigging and Reliability

The Badami Sales Oil Pipeline did not transport any oil during 2008. No gas was transported from Endicott through the Badami Utility Pipeline during 2008. Table 14 summarizes throughput and pigging information for the Badami Pipelines. Appendix K provides a listing of throughput for all SPCO jurisdictional pipelines.

Table 14. Throughput and Pigging Information for the Badami Pipelines, 2008.

Pipeline System	2008 Throughput	MOP	Maintenance Pigging	Last ILI	Pipeline Operator
Badami Sales Oil	Not in service	1,415 psig at 150° F (design)	Not in service	2007*	BPXA
Badami Utility	Not in service	Not in service	Not in service	Never	BPXA

** ILI run at decommissioning of sales oil pipeline (August 27, 2007). No data gathered beyond mile 5.9.*

<u>Assurance Programs</u>

DOT Integrity Management Program

The formal risk assessment for the BPTA's pipelines, including Badami was conducted on May 20, 2008. Only one item, the hiring of a DOT coordinator, was identified as a P&M measure for Badami, (There were none in 2007 and 10 in 2006.) There were no accident reports, no PHMSA Safety-Related Conditions reported and no PHMSA Notices of Probably Violation were issued FY 2008.

Quality Assurance
The primary tool for tracking obligations under this and other programs is an electronic tracking system. This system tracks regulatory requirements, responsible parties, and identifies operational controls. This system will generate project specific reports for individuals and will notify management of exceptions to meeting any obligations.

The BP Global Audit Team conducted an evaluation of all BPXA operations, North Slope and Anchorage in January 2008. This audit included the Badami pipelines over which SPCO has the ROW authority. No results were shared in this annual report.

During 2008, BPXA facility radio systems were upgraded with Harmony Radios. These radios provide enhanced field-wide connectivity and consolidated the communication platform for BP operated areas on the North Slope, fire, police, and other emergency responders. These various communication systems are used in BPXA's day-to-day operations and by the first responders during emergency response and weekly training.

Personnel Safety Programs
Internal Safety Program:
The Badami oilfield is in warm shutdown so activity in the oilfield and on the pipeline is greatly reduced. The numbers reported reflect both the field and pipeline operations. The internal safety program for Badami, in which employees formally monitor their own and other's safety behavior, is called ORCA. Employees reported 62 safety related observations/conversations or behaviors, both positive reinforcement and items deserving attention. For the last three years, there have been no OSHA days away from work, no OSHA recordable accidents, no OSHA first aid incidents and no major incidents reported for the Badami pipeline.

External Safety Program:
Contractors working at Badami or on the Badami pipeline were required to obtain "Authorization to Proceed" from a BPXA operations supervisor before initiating the work. For certain activities, contractors also had to perform a task hazard analysis prior to receiving their authorization to proceed. Contractors also participated in the same internal safety program as BPXA employees. There were no OSHA days away from work, no OSHA recordable accidents, no OSHA first aid incidents and no major incidents reported to BPXA on behalf of the contractors working at Badami.

Corrosion Program
All BPXA pipelines are on a 3-year ILI schedule. For Badami, however, there will not be another ILI run until it returns to service. While no date has been set to recommission the line, corrosion coupons will likely be installed during FY 2009 or early FY 2010.

An inspection by the Corrosion Inspections and Chemical (CIC) group in July 2008 examined the external fusion bonded epoxy coating for any mechanical damage. They found minor damage at three pipe supports. There was no evidence of corrosion and no physical damage to the pipe. The coating will be repaired during the 2009 tundra travel season.

A cathodic protection survey was completed at the river crossings in September 2008. BPTA notes that the survey met the 49 CFR 192 and 195 requirements. Pipe-to-soil potentials were measured with portable reference electrodes at above/below ground transitions associated with river crossings. BPTA notes that the fixed reference electrodes are inaccurate but that there are no present plans to replace these because they do not affect the operation of the cathodic protection system.

Surveillance & Monitoring Programs

Aerial Surveys

There were 67 aerial inspections of the Badami pipeline during 2008 that met regulatory requirements. One of the over flights included FLIR technology aerial assessments. Concurrent with some of the ground surveys Badami pipelines also received three helicopter inspections.

Ground Surveys

In addition to the aerial inspections, the pipelines were visually inspected during the annual Walking Speed Survey conducted on March 27, 2008. Eleven observations were noted on the Sales Oil Pipeline: one jacked VSM, one saddle off the VSM, four areas of broken insulation straps/bands, one location with cracked/broken patch over existing hole, three locations with dented or crushed insulation, and one location was missing sealant on insulated weld pack.

There were 85 observations made along the Badami Utility Pipeline of items needing repair or monitoring. Of these, 46 involved missing or broken vibration dampeners, 33 involved misaligned vibration dampeners and there were two locations where misalignment of the pipeline put it in contact with adjacent saddles. The Endicott maintenance team will follow up on all surveillance items through their work order system.

Additional site investigations were completed up to Mile 5.9 on the Badami Sales Oil Pipeline. Smart pig runs in 2007 indicated no imminent threat to pipeline fitness. Work in 2008 verified a sample of anomalies that had been previously noted and correlated them against reported conditions. An ILI of the full 25-mile line segment will not be conducted until such time that Badami is brought back into service.

2008 Activities

Construction Activities

There were no construction activities on the Badami Pipelines in 2008.

Badami Weir

The Badami Weir at the Sagavanirktok River crossing is covered under the lease as a “related facility” to the Badami Pipelines ROW. Permits issued by the U.S. Army Corp of Engineers (USACE) and ADF&G require a minimum of three summer-time inspections of the weir, focusing on bank erosion, flooding and surface water conditions. The weir was inspected on June 25, July 15, and August 6, 2008.

Long-term corrective action for the weir was approved by the USACE on October 14, 2008, and calls for:

(1) removing short-term measures implemented in 2007 (temporary dikes and gravel bags);
(2) installation of two Jersey barriers; and
(3) developing as-builts;
(4) continuing with current surveillance programs; and
(5) inspecting the weir during September 2009 to observe any consequences of August flooding season.

Maintenance Activities
BPTA maintains a computerized maintenance management system for all of its fields designed to comply with the requirements of existing regulations. In 2008, PHMSA jurisdictional equipment was inspected and maintained. Installation of vibration dampeners was completed. The pig launcher on the Endicott side was sandblasted and coated. Remote Terminal Unit were inspected and maintained and a cathodic protection survey was conducted in September 2008.

<u>2009 Proposed Actions and Plans</u>
Table 15 provides BPXA's 2009 schedule for surveillances, audits, self-assessments, and evaluations.

Table 15. Table of Proposed Actions and Plans

Quarter/Activity	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Aerial Inspections Every 2 Weeks	✓	✓	✓	✓
Start-Up Activities		✓		
Cathodic Protection Survey				✓
Ground Survey		✓		
Weir Work and Monitoring		✓	✓	
Risk Assessment Review		✓		

Badami weir monitoring (3rd Quarter) includes monitoring of the Sagavanirktok River.

4.2.1.3 Oversight Activities of the State Pipeline Coordinator's Office

(*This section provides a summary of SPCO activities. Information in this section reflects the work efforts of the State Pipeline Coordinator's Office and is not taken from the Lessee's annual report. By the nature of the SPCO work, there will be some overlap of information.)*

<u>SPCO Lease Compliance Section</u>

FY09 SPCO activities at Badami focused on review of the SMP, the Alaska Hire Report, general ROW lease conditions, engineering design review and performing field inspections.

The Lease Compliance Team made three trips to inspect the Badami pipeline operations, ROWs and, specifically, the Badami weir site in FY09. A total of 20 surveillance reports were completed, all of which resulted in satisfactory conditions.

Badami Weir

The weir was initially constructed in 2002 to mitigate the erosion and drainage problems resulting from construction of the pipeline river crossing on the East Channel of the Sagavanirktok. By 2007, it became apparent that the weir performance was not acceptable. An interim solution provided bank stabilization and minimized erosion using sand and gravel bags (Figure 55). Plans for a more permanent weir structure that could maintain the stability of the adjacent wetland communities, mitigate accelerated erosion and thwart possible impacts to the Badami Pipelines over the long-term was approved and modifications to the existing weir were completed during the 2008 winter season. These modifications included removing the two temporary dikes and the hundreds of gravel bags installed in 2007. They were replaced with two dikes formed with precast concrete jersey barriers. These barriers are designed to direct the flow of water over the weir, restoring the original surface flow patterns and maintaining the elevation of an upstream oxbow lake.

The disturbed project area will be rehabilitated beginning late summer 2009. When overburden stockpiled at the site (Figure 56) thaws, it will be spread over approximately 5,200 square feet of bare ground, seeded with native species, and fertilized in order to promote the successful establishment of plant communities.

Figure 55. *Aerial photo of Badami Weir taken in 2007.*[13]

Modifications to the existing weir were completed during the 2008 winter season. These modifications included removing the two temporary dikes and the hundreds of gravel bags that had been installed in 2007 (Figure 55) and replacing them with two dikes comprised of precast concrete jersey barriers that are 63 feet long. The jersey barriers will corral and direct the flow of water sending it over the weir, further reducing erosion and sedimentation along the East Channel of the Sagavanirktok River Crossing. On January 29, 2009, BP submitted the Rehabilitation Plan for Badami Pipeline Weir in accordance with a general condition of USACE issued Department of Army Permit POA-1994-700-2.

On May 10, 2009, the SPCO visited the weir site to observe its performance and examine the area for any sign of further erosion (Figure 56). Water was flowing over the weir as anticipated and the integrity of the Badami Pipelines was not at risk. On June 17, 2009, the SPCO Representative returned to the weir site to view any effect break-up may have had on the weir, or any impacts that may have occurred due to weir performance. The weir appeared to have handled the flow resulting from break-up well and water levels at the adjacent lake were maintained during the break-up period. It should be emphasized that this was the spring that the new design was in use. Continued monitoring of the site

[13] ***Image found in the REHABILITATION PLAN FOR BADAMI PIPELINE WEIR Department of the Army Permit No. 2-1994-0700, Mikkelsen Bay 2 Prepared by: BPXA.; Environmental Studies Group Anchorage, Alaska January 30, 2009.***

is important and the Lessee is required to conduct three summer surveys of the weir until the area is adequately stabilized. The surveys assess bank erosion, flooding conditions, and surface conditions.

As part of the modification plans to enhance weir performance, the project site is to be rehabilitated beginning late summer 2009. After the overburden stockpiled at the site thaws (Figure 56) rehabilitation efforts will begin with spreading the overburden to cover approximately 5,200 square feet of bare ground. After the bare ground is covered, it will be seeded with native vegetation and fertilized in order to promote the successful establishment of plant communities.

Figure 56. *Stockpiles of overburden are to be spread around the Badami Weir late August 2009.*

ROW Surveillance

Helicopter and ground vehicle surveillances were conducted during all three SPCO field inspections. While flying over the entire Badami Oil ROW there was no evidence of impediment or alteration of caribou and other large mammal movement patterns observed. Additional surveillance of the ROW produced no unsatisfactory findings.

<u>SPCO Right-of Way and Permits Section</u>:

Badami Weir:

The Badami weir is located on the west bank of the East Channel of the Sagavanirktok River. Access during the summer months is via helicopter, boat, or possibly Rolligon, and during the winter months via tundra travel or ice road on the Sagavanirktok River. On December 9, 2008, the SPCO received a *Badami Weir – Phase 2 Civil Scope of Work Issued for Construction Report* from BP Transportation, Inc. The report, prepared by a consultant, provided the final construction drawing detail for a long-term alternative to be implemented for the Badami Weir site. On February 3, 2009, the SPCO also received a copy of the *Rehabilitation Plan for the Badami Pipeline Weir*, POA-1994-700-2, submitted to the USACE. The rehabilitation plan was prepared by the BPXA, Environmental Studies Group.

On March 4, 2009, the SPCO sent a letter to BPTA conditionally approving the activities described in the Engineering report (see SPCO Letter No. 09-027-TG). Project mobilization occurred in March and weir construction activities were completed in April. On July 1, 2009, the SPCO received a copy of the Badami Pipeline Sagavanirktok River Crossing, June Monitoring Report. The report documented a June 17, 2009 inspection of the Badami Weir conducted by BPXA staff. It indicated that water flow was impounded by the weir and that bank erosion was not observed with respect to the weir, but that deep news rills were on the tundra bank of the East Sagavanirktok River Channel south 100 feet upstream.

Badami ROW Survey Corrections:
The SPCO met with BPTA in October 2008 to discuss the Badami Oil and Badami Utility construction rights-of-way and the status of pipeline ROW surveys. It was determined that additional survey work was needed to make corrections and clarifications related to existing and pending survey plats, including EPF 200218, EPF 200806, and EPF 200809. Several meetings occurred between the DNR review surveyor, SPCO staff, BPTA staff, and the BPTA contract surveyor to discuss survey issues. Several draft survey drawings were submitted to the DNR surveyor for review and the DNR surveyor provided specific comments and edits to the drawings submitted. BPTA has requested that the surveyors prioritize the survey reviews. It is anticipated that the Badami Oil and Badami Utility ROW survey drawings will be completed and approved by DNR during FY10. After the ROW surveys are approved, the information will be used to complete releases of interests of construction rights-of-way for each pipeline, thus adjusting the ROW size and acreage to amounts specified for pipeline operations and maintenance.

<u>SPCO Engineering Review: Badami Sales Oil and Gas Pipelines</u>
During this reporting period, both pipelines were unused. The fuel-gas pipeline is only used to startup the Badami facilities. It provides energy to run equipment for a period, until Badami wells were able to produce gas. The oil line was only active when Badami produced oil. The reservoir’s production well rates are well below original estimates. As a result, the Badami pipeline flowed at very low rates. Because of economics and operability issues, BP elected to shut in Badami for a period to allow the reservoir to recharge and, hopefully, produce at higher rates for a period in the future.

With no pipeline operation, the operator’s efforts at Badami focused on the installation of a revised weir design. The weir was originally installed as a temporary expedient to stop a flow path from an oxbow lake that was inadvertently being drained by the installation of the trenched pipeline crossing. Additional information on the weir is found in other sections of this report.

4.2.1.4 State Fire Marshall's Office

Annual Fire Prevention and Life Safety Inspections of Badami facilities were conducted by the SFMO on February 5, 2009. Inspections covered both process and non-process areas. The inspections were successfully conducted with the help of BP Fire and Safety Personnel and Badami Operations Personnel.

Eight violations were found during the inspection of the Badami facilities. Many of those violations were minor and were either corrected on the spot, or put on work orders or preventative maintenance.

4.2.2 Endicott Pipelines

Figure 57. *Endicott Pipeline bridge over Little Skookum.*

4.2.2.1 Right-of-Way Lease and Pipeline System Overview

The Endicott Development is located offshore in the Beaufort Sea, about 15 miles east of Prudhoe Bay. The facilities are located approximately 2.5 miles seaward of the Sagavanirktok River Delta and shoreward of the barrier islands, in water up to 14 feet deep. The Endicott facility includes the MPI, the Satellite Drilling Island SDI, and Endeavor Island immediately adjacent to the MPI. They are linked to shore by a 1.9-mile long causeway that extends from the Sagavanirktok River delta to the Inter-island causeway that links the MPI and the SDI. The causeway has three permanent breeches placed to ensure fish passage and maintain water quality. Figure 57 above, shows one of the bridges on the Endicott causeway. A 1.5-mile gravel approach connects the southern end of the causeway to the Sagavanirktok River Delta uplands where it connects with an eight-mile gravel road that tie into the Prudhoe Bay road system. This provides year-round access to Endicott facilities and pipelines.

The Endicott Pipeline transports processed crude oil from the Endicott Development approximately 26 miles above ground on VSMs to TAPS PS 1. The 16-inch diameter pipeline begins at Endicott's MPI (Module 303) and is mounted on VSMs along the causeway to shore, where it parallels the road system to PS 1. At PS 1, there is a pig receiver and metering facilities. The Badami Oil Pipeline ties into the Endicott Pipeline at approximately the mid-point. Additional information regarding the physical features of the Endicott Pipeline can be found in Appendix E (Physical Characteristics of SPCO Jurisdictional Pipelines). During 2006, Flow Stations 1 and 2, and the crude oil topping unit (COTU) were tied into the Endicott Pipeline, allowing oil from GPB to temporarily route some of its production through the Endicott Pipeline to PS 1. However, during 2008 the connections from FS 2 and the COTU were permanently decommissioned and “air-gapped.” The pertinent pipe sections were removed and replaced with blind flanges and vent taps. The Endicott Pipeline is again operating as originally designed.

The operations ROW for the Endicott Pipeline is approximately 150 feet wide, except along the causeway, where the ROW is 500 feet wide (Appendix G, Acreage, Survey, and Lease Information). The pipeline crosses the West Channel of the Sagavanirktok River on a pipe bridge. The as-built for Endicott Pipeline alignment in the area of the new GPB connections was drawn incorrectly. A new survey of the location has been completed and a minor lease amendment is in progress.

4.2.2.2 Annual Report

BPTA submitted its annual report to the SPCO on February 4, 2009, which presented information for seven pipelines, including the Endicott Pipelines. The report format paralleled the SPCO reporting requirements and met SPCO expectations, as set forth in Appendix J (SPCO Annual Reporting Requirements for Lessees) of this report. BPTA and the SPCO maintain good communications and meet quarterly to discuss issues pertaining to the lease, including BPTA updates on activities and plans related to all BPTA pipelines (Appendix F, Lease Required Contact Information).

Significant items excerpted and extracted from the BPTA Annual Report regarding this line are presented below.

Operations – Throughput, Pigging and Reliability

The Endicott Pipeline transported oil during 2008. No unplanned shutdowns occurred during 2008. The next Smart Pig run will take place in 2011. Maintenance pigging takes place every quarter. Table 16 reflects CY08 data for the Endicott Pipeline. Appendix K provides a listing of throughput for all SPCO jurisdictional pipelines.

Table 16. Throughput and Pigging Information for the Endicott Pipeline, 2008.

Pipeline System	2008 Throughput	MOP	Maintenance Pigging	Last ILI	Pipeline Operator
Endicott	5,481,023 net barrels	1,200 psig at 180° F (operating)	Quarterly	2008	BPXA

Assurance Programs

Quality Assurance

The BP Global Audit Team conducted an evaluation of all BPXA operations, North Slope and Anchorage in January 2008. This audit included the Endicott Pipeline over which SPCO has the ROW authority. No results were shared in this annual report.

All radio systems were upgraded with Harmony Radios to enhance connectivity between all BP fields. The upgrade consolidates the communication platform so that BP operated areas can have reliable communications with fire, police, and emergency responders within the North Slope. These systems are used for BPXA's daily operations and for weekly training.

All analysts performing the MFL inspection on June 16, 2008 had to complete an auditable written procedures exam to ensure that only qualified analysis personnel analyze MFL data.

Criteria for Pipeline Integrity Management Systems, CRT-AK-49 4.2; for formal review of pipeline fitness for operations was used during the formalized annual review of the Endicott Pipeline condition and fitness assessment for continued operations. Status of the P&Ms and action items from 2006-2007 and the number of candidate P&Ms and action items for 2008 for BPXA's Annual summary Integrity Reporting concluded that there was one P&M and 12 Action items. The next Risk Assessment is scheduled for March 2009, which allows for time in completing action items and effectively developing annual work plans within BPXA operations.

Personnel Safety Programs

Internal Safety Program

Employees formally monitoring themselves and each other's safety with behavior-based techniques called ORCA submitted 323 safety related observations. Safety Observations and Conversations between management and employee totaled 951. There was one OSHA recordable accident/incident and four reportable incidents of first aid. The OSHA recordable and first aid incidents occurred near Pump Station 1 during the pipeline renewal project.

External Safety Program

Contractor safety is managed by BPXA's Internal Safety program. Contractors participate in the ORCA, BEST, and STOP programs just as BPXA employees do. Before initiating a larger project, Authorizations to Proceed and Task Hazard Analyses is completed.

DOT Integrity Management

On May 20, 2008, the formal risk assessment for BPTA lines was conducted; it included Endicott Pipeline. The assessment identified preventative and mitigative (P&M) measures to reduce the risk of a pipeline failure. For Endicott only one item was identified by the Lessee as a candidate for a P&M measure. There were no PHMSA identified safety related conditions for 2008, and no PHMSA notices of probable violations issued in 2008. Additionally, no abnormal operating conditions were cited.

An inspection of the OTL 12 Pre-Startup Design, Construction, and Pressure Testing Records was performed by PHMSA from August 25 through 27, 2008. PHMSA reported that there were no enforcement actions; all information requested by the PHMSA inspector was produced on-site and provided directly to the inspector during the audit.

Corrosion Program
Endicott Oil Pipelines had two In-line Inspections, one in June and one in July. The Smart Pig runs did not indicate any anomalies defined by USDOT in 49 CFR 195.452, Section H. The ILI was performed in accordance with BPXA's Criteria for ILI. For more information on the results of the ILI, please see the Surveillance and Monitoring section on the following pages.

<u>Surveillance & Monitoring Programs</u>
The SMP is designed to detect and abate situations that endanger health, safety, environment, or pipeline integrity. The program was reviewed and approved by the SPCO.

Ground Surveys
During 2008, sixty-five drive-by surveillances of the Endicott Pipeline were conducted in compliance with PHMSA requirements and Endicott Pipeline Lease commitments. During these inspections, any changed or unusual conditions on or adjacent to the pipeline ROW is documented, and receives follow up as appropriate. Items identified during these surveillances included a misaligned side hatch on a valve enclosure and seepage at a stem valve.

In addition to the drive-by inspections, The *Annual Ground Inspection/Walking Speed* Survey (WSS) was conducted on November 1 through November 14, 2008 on the Endicott Pipeline. BPTA reports that there were no pipeline integrity concerns documented. The survey did find instances of vertical settlement of two VSMs, 4 feet of missing insulation, 5 locations with dented and/or crushed insulation and 47 locations of perforations to the insulation jacketing. Also, nearly all weld packs need their outer edges sealed.

Monitoring
The Endicott Oil Pipeline was subject to two, ILI during FY 2008. The first, on June 16, used a high-resolution MFL inspection tool collected data with results showing a total of 238 metal loss anomalies that were greater than or equal to a minimum predicted wall loss of 10% being detected.

The second ILI, on July 22, used the ROSEN tool, which combines MFL and ultrasonic testing. This inspection revealed 474 anomalies. Most anomalies were caused by corrosion, with defects between 10 and 19% wall loss. The highest wall loss reported was 43%.

A site investigation plan has been developed that correlates these data from both 2008 inspections and previous In-Line Inspections, and will be implemented over the next three years. The next smart pig run will take place in 2011.

2008 Activities

Construction Activities

During 2008, the connections from FS 2 and the COTU were permanently decommissioned and "air-gapped."

During the winter, an ice ramp and road on the Endicott SDI was constructed to cross the underground portion of the pipeline. The purpose of the ice road was to transport heavy equipment and facilities to support a drilling program at the SDI.

Maintenance Activities

The pig launcher (Endicott side) was sandblasted and coated.

Removal of pipe sections between COTU and FS 2 and the Endicott Oil Pipeline and replacement with blind flanges and vent taps occurred in the Endicott ROW. The connections from FS 2 and the COTU were permanently decommissioned and "air-gapped.

Unplanned Events

Oil and Hazardous Waste Discharges

Two reportable discharges occurred and were reported: 1) a snow blower removing snow from Endicott Ice Road experienced a hose failure resulting in a material release and, 2) a bus had a transmission fluid spill on the Endicott access road en route to Deadhorse.

Other discharges, however non-reportable were:

(1) Hydraulic oil was released from a snow blower's hose failure in the Endicott ROW,
(2) Glycol leaked from a failed coolant hose on a CH2Mhill Vac Truck in the Endicott ROW,
(3) Diesel from a Rolligon leaked into containment on the Endicott ROW,
(4) Transmission fluid leaded from a pick-up in the Endicott ROW
(5) Diesel from a bus leaked into containment on the Endicott ROW and,
(6) Glycol leaked from a heater hose on a truck hauling water on the Endicott ROW.

Spill Response

If spill response equipment is not available or a significant change has occurred with pipeline leak detection and it no longer meets DEC regulatory requirements *Non-readiness Notifications* are required.

Two Non-readiness Notifications were made during 2008, 1) In March, DEC was notified that a planned upgrade was going to be made that may affect the Endicott Pipeline leak detection system and, 2) in April, DEC was notified that a control panel, in Module 303, was being replaced that may affect the leak detection for up to two hours. Work had been scheduled to begin within 24-hours of the notice being sent.

Lease Administration

Two scrivener's errors were corrected and officially recorded for the Endicott Pipeline.

Drawings to expand operating parameters for the Endicott tie-in connections and the utility line on the Endicott causeway were submitted to DNR and action is pending.

Endicott Pipeline functioned within the ROW boundaries specified within Lease.

<u>2009 Proposed Actions and Plans</u>
Table 17 provides BPXA's 2009 schedule for surveillances, audits, self-assessments, and evaluations.

Table 17. Table of Proposed Actions and Plans

Quarter/Activity	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Drive-by Inspections Every Two Weeks	✓	✓	✓	✓
Ongoing Field Verifications of 2008 Smart Pigging	✓	✓	✓	✓
Cleaning and Maintenance Pigging	✓	✓	✓	✓
Ground Survey (WSS)		✓		
Risk Assessment Review		✓		

In addition to these commitments, BPXA will complete the final pipeline disconnection of FS2 and COTU by removing pig bars and replacing pipe coupons (2nd quarter), and extending the under-road casings upwards outside the existing road vaults at MPI-SDI intersection (3rd Quarter).

4.2.2.3 Oversight Activities of the State Pipeline Coordinator's Office

(*This section provides a summary of SPCO activities. Information in this section reflects the work efforts of the State Pipeline Coordinator's Office and is not taken from the Lessee's annual report. By the nature of the SPCO work, there will be some overlap of information.)*

<u>SPCO Compliance Section</u>
The Compliance Section traveled along the Endicott Right-of-Way twice during the reporting period covered by this report. The first trip was on August 28, 2008 and the second trip took place on June 17, 2009. Both trips were intended to familiarize staff with the ROW and associated facilities and to do conduct surveillance work. The earlier trip was done in conjunction with the SPCO Engineering Section. Typically, trips often result in several separate surveillance reports. Ten surveillance reports were produced as part of the two compliance section trips related to the Endicott lease.

Capturing Bridge Location Information
On the August 28, 2008 trip, the Compliance and Engineering sections accompanied BPTA and BPXA staff to the Endicott Main Production Island. During the trip, the SPCO staff noted that Endicott has had an ongoing and successful participation in the VPP. Following a tour of the Main Production Facility, the SPCO staff returned to the BP Operations Center, stopping at three bridges along the causeway, and the crossing at the Sagavanirktok River to take Global Positioning System set points and photograph the

vehicular and pipeline bridges. Figure 58 is a photograph of Endicott Causeway Bridge 2, which was taken on the August 28, 2008 trip.

Figure 58. *Endicott Causeway, Bridge number 2, N 70.31290, W 147.88312.*

Casing in Right-of-Way

The trip in June of 2009 did not cover the entire ROW. During this trip, SPCO staff noted that pipe casings were located along the ROW. The casings are used to protect piping from excessive snow at the 'T' intersection on the Endicott Causeway. The casings were staged and awaiting installation.

<u>SPCO Right-of-Way Section</u>:

Survey Correction and Lease Amendment Request:

During September 2006, while SPCO reviewed information associated with temporary transit line connections to the Endicott Pipeline, an error was noted indicating that the Endicott pipe was built outside the surveyed ROW boundaries of ADL 410562 (per ASLS 84-96) within Section 33, T. 11 N., R.15 E., Umiat Meridian, AK. Draft survey drawings were submitted and reviewed by the DNR survey section during 2008. The as-built survey, *Record of Survey of the Endicott Right-of-Way*, EPF 20080040, was recommended for approval by the statewide platting officer January 21, 2009 and the plat recorded January 29, 2009 in the Barrow Recording District as Document 2009-000037-0. On July 15, 2009, the SPCO received a letter from BPTA requesting the ROW lease for Endicott Pipeline be amended to include an additional 1.18 acres. The lease amendment request will be processed and completed during FY10.

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4.2.3 Milne Point Pipelines

Figure 59. *Milne Point Product and Milne Point Oil are the pipelines on the left side of the photograph.*

4.2.3.1 Right-of-Way Lease and Pipeline System Overview

There are two SPCO jurisdictional pipelines associated with Milne Point operations, a sales oil pipeline, the Milne Point Pipeline and a NGL product supply pipeline, the Milne Point Product Pipeline. Figure 59 is a photograph of both of the Milne Point pipelines. Milne Point Pipeline was built in 1984-85 to transport processed sales oil from the Milne Point Unit to the Kuparuk Pipeline System. The approximately 10-mile Milne Point Pipeline connects the Milne Point Central Facilities Pad (CFP) at Module 58 to the Kuparuk Pipeline at a point that is shortly beyond Module 68, after crossing under Spine Road, just east of CPF-1. The Milne Point Pipeline is piggable from the Milne CFP to Module 68. A pig receiver, metering equipment, and leak detection equipment are at this location.

The Milne Point Products Pipeline was built in 2000 and placed on the same supports as the Milne Point Pipeline to transport NGL from the Oliktok Pipeline to Milne CFP to be used in enhanced oil recovery. The NGL products pipeline was shutdown in 2002 and has not been operated since. In December 2006, with SPCO authorization, the Milne Point Products Pipeline was purged and physically disconnected from the Oliktok Pipeline. Both of the pipelines have year-round ROW road access.

The 14-inch oil pipeline is piggable, with the exception of a short length between Module 68 and the Kuparuk tie-in. This short section of unpiggable pipeline was replaced in 2007 with corrosion-resistant duplex stainless steel.

The NGL products pipeline is an eight-inch pipeline. Both lines are supported by above-ground VSM support systems. Specific physical characteristics of the pipelines are provided in Appendix E, Physical Characteristics of SPCO Jurisdictional Pipelines.

The ROW for the Milne Point Pipeline is at its operational width, approximately 150 feet wide. The ROW for the NGL products pipeline is still in construction width, varying from 185 to 800 feet. An as-built survey will need to be submitted to the State to initiate the Release of Interest process. In 2006, the Lessee abandoned the NGL-carrying Milne Point Products Pipeline, per USDOT regulations. The NGL products pipeline was physically disconnected and taken out-of-service, eliminating PHMSA oversight. The state ROW will remain in effect until the pipeline lease is formally terminated. Additional lease information can be found in Appendix G, Acreage, Survey, and Lease Information.

4.2.3.2 Annual Report

BPTA submitted its annual report to the SPCO on February 4, 2009, which presented information for seven pipelines, including the Milne Point Pipelines. The report format paralleled the SPCO reporting requirements and met SPCO expectations, as set forth in Appendix J, SPCO Annual Reporting Requirements for Lessees, of this report. BPTA and the SPCO maintain good communications and meet quarterly to discuss issues pertaining to the lease, including BPTA updates on activities and plans related to all BPTA pipelines (Appendix F, Lease Required Contact Information).

The Milne Point Sales Oil Pipeline transported 11,801,237 net barrels of oil to the Kuparuk Pipeline during 2008. No natural gas liquids were transported in the Milne Point Products Pipeline during 2008. Table 18 describes the throughput, MOP, pigging and operator information for the Milne Point Oil and Product pipelines.

Table 18. Throughput and Pigging Information for the Milne Point Pipelines, 2008.

Pipeline System	2008 Throughput	MOP	Maintenance Pigging	Last ILI	Pipeline Operator
Milne Point Pipeline (Oil)	11,801,237 net barrels	1,350 psig	Quarterly	2008	BPXA
Milne Point Product Pipeline (NGL)	Not in service	Not in service	Not in service	n/a	BPXA

Milne Point had an unintended shutdown on April 29, 2008 accidentally caused by an Alyeska technician at PS1.

Significant items excerpted and extracted from the BPTA Annual Report regarding the Milne Point pipelines are presented below.

Assurance Programs

DOT Integrity Management

On May 20, 2008, the annual risk assessment of the Milne Point Pipelines was conducted. Only one item, the hiring of a DOT coordinator, was identified as a P&M measure for Milne Point. (There were none in 2007 and 18 in 2006, the first year the Milne Point Pipelines were included in the annual risk assessment process.) Seven related action items were also identified.

BPTA conducted other activities under USDOT regulations including 29 drive-by inspections of the Milne Point Pipelines, which met and exceeded the PHMSA required surveillance requirements for 2008.

The Milne Point Oil Pipeline undergoes two main valve and one annual relief valve inspection each year to meet PHMSA regulation requirements. No changes were identified by these inspections during 2008.

PHMSA issued a notice of possible violation at Milne Point on September 10, 2008 for lack comprehensive internal corrosion control procedures, and inadequate pipe coating.

Quality Assurance

The primary tool for tracking obligations under this and other programs is an electronic tracking system. This system tracks regulatory requirements, responsible parties, and identifies operational controls. This system will generate project specific reports for individuals and will notify management of exceptions to meeting any obligations.

BP Global Audit Team conducted an evaluation of all BPXA operations, North Slope and Anchorage in January 2008. This audit included the Milne Point pipelines over which SPCO has the ROW authority. No results were shared in this annual report.

The BPXA US DOT adviser traveled to the North Slope four times during 2008, as part of lease and PHMSA compliance efforts. On two of those trips, USDOT training was provided.

During 2008, BPXA facility radio systems were upgraded with Harmony Radios. These radios provide enhanced field-wide connectivity and consolidated the communication platform for BP operated areas on the North Slope, fire, police, and other emergency responders. These various communication systems are used in BPXA's day-to-day operations and by the first responders during emergency response and weekly training.

Safety Programs

Internal Safety Program:

At Milne Point, in the last year, employees submitted 1,813 safety related observations. These observations include items such as suggestions or positive reinforcement of observed good practices, as well as, deficiencies. The effectiveness of the program is demonstrated by the safety statistics. For the last three years, Milne Point has had no reportable OSHA days away from work, OSHA recordable accidents/incidents, OSHA first aid, or major BPXA incident reports for pipelines for the last three years.

External Safety Program:

Contractors working at Milne Point or on the Milne Point pipeline were required to obtain a signed Authorization to Proceed from a BPXA operations supervisor before initiating the work. For certain activities, contractors also had to perform a task hazard analysis prior to receiving their authorization to proceed. Contractors also participated in the same internal safety program as BPXA employees. There were no OSHA days away from work, no OSHA recordable accidents, no OSHA first aid incidents and no major incidents reported to BPXA on behalf of the Contractors working at Milne.

Corrosion Program

On June 3, 2008, there was an ILI inspection of the Milne Point pipeline. This was a high-resolution Magnetic Flux Leakage metal loss in-line. Follow up investigations to verify a sample of the anomalies noted was initiated. A site investigation plan based on correlating previous inspections with the 2008 inspection has been completed. No findings as outlined in 49 CFR 195.452 Section H, were identified during the smart pig inspection.

The next smart pig run will take place in 2011.

Surveillance & Monitoring Programs

The SMP is designed to detect and abate situations that endanger health, safety, environment, or pipeline integrity. The program must be reviewed and approved by the SPCO. BPTA submitted a revised program this year that included an expanded matrix, which included details about surveillances, monitoring, maintenance and other requirements for both active and out-of-service pipelines.

Ground Inspection

Drive by and walking-speed inspections are required by the BPTA Surveillance and Monitoring Program as well as USDOT regulations. PHMSA requires drive-by inspections at Milne Point at an interval no greater than once every three weeks, and at least 26 times a year.

During 2008, Milne Point Security conducted 29 drive-by inspections of the line in fulfillment of PHMSA inspection requirements. Milne Point operators requested 79 additional inspections in response to unexplained leak detection alarms. BPTA notes that the term “unexplained” means the Mass Pack alarm did not clear within 10 minutes. Many of the alarms listed communications loss as an issue. The operator reports that, during the reporting period, Harmony Radios were used to enhanced communications.

The annual ground inspection/walking speed surveys were conducted on October 28 and 31. There were 47 observations noted, 15 involved minor perforations to the insulation jacketing, and 25 were related to broken/damaged dampener issues. Seven observations were recorded for the Milne Point Products Pipeline. Four observations involved perforations to insulation jackets, three weld pack locations were missing insulation. The Milne maintenance teams will follow up on surveillance items through their work order system.

The low point drain and auxiliary piping located on the ROW by module 68 was inspected. No corrosion on the piping was noted, a small amount of corrosion was found on the drain.

2008 Activities

Construction Activities
No construction was conducted at Milne Point Pipelines during 2008.

Maintenance Activities
BPTA maintains a computerized maintenance management system for all of its fields designed to comply with the requirements of existing regulations. In 2008, PHMSA jurisdictional equipment was inspected and maintained.

The oil pipeline was lifted approximately ½" under the 12-inch BP check valve allowing ConocoPhillips to make a corrosion inspection at the tie-in.

Jersey barriers were installed to protect the Milne Point pipelines crossing under the access road to West Sak 24A Pad.

The communications upgrade to Module 68 was completed in early 2009.

Cleaning and maintenance pig runs took place for the sales oil pipeline. A smart pig was run during June 2008 (discussed above). A nitrogen blanket was introduced into the products pipeline when that service was discontinued. The "blanket" is monitored and recorded daily.

Unplanned Events
There were six minor communications failures at Milne Point during 2008. One communications problem required a non-readiness report to the DEC because there was no spill response equipment available at a time when there was a short-term communications problem affecting the leak detection system.

Spill Response
If spill response equipment is not available or a significant change has occurred with pipeline leak detection and it no longer meets DEC regulatory requirements *Non-readiness Notifications* are required. The Milne Point Pipeline ROWs experienced two minor reportable spills during calendar year 2008. The first of these was in March 2008 when a water truck hose failure led to an antifreeze spill. In December of 2008, a third party vehicle went off the road by Module 68.

2009 Proposed Actions and Plans

Table 19 provides BPXA's 2009 schedule for surveillances, audits, self-assessments, and evaluations.

Table 19. Table of Proposed Actions and Plans, Milne Point Pipelines

Quarter/ Activity	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Drive-by Inspections Every Two-Weeks	✓	✓	✓	✓
Ongoing Field Verifications of 2008 Smart Pigging	✓*			
Cleaning and Maintenance Pigging	✓*	✓*	✓*	✓*

** Milne Point Oil Pipeline*

Additional activities planned for the 2009 calendar year include, the Annual Risk Assessment Review of the Sales Oil Pipeline (DOT Integrity Management Program) during March 2009. Twice during 2009, the Lessee has plans to verify that the stainless steel pipe is isolated from the carbon steel pipe. During the fourth quarter of 2009, a Ground Survey (WSS) is planned for the Milne Point Pipelines.

4.2.3.3 Oversight Activities of the State Pipeline Coordinator's Office

(*This section provides a summary of SPCO activities. Information in this section reflects the work efforts of the State Pipeline Coordinator's Office and is not taken from the Lessee's annual report. By the nature of the SPCO work, there will be some overlap of information.)*

SPCO activities at the Milne Point Pipeline during FY09 focused on safety procedures, facility access and wildlife management. The section below highlights both observations of those activities and some of the issues and follow up identified during this period:

<u>SPCO Surveillance Field Trips</u>

The SPCO Compliance Section traveled to the North Slope and observed the Milne Point Pipeline one time during FY09. This trip produced 14 surveillances and one field report addressing the Milne Point Pipeline and facility access, safety procedures and general right-of-way lease conditions.

The trip, taken on August 28, 2008, was part of a combined pipeline ROW trip, taken to observe several jurisdictional pipelines on the North Slope. Fourteen surveillance reports related to facility access afforded the team, pipeline access, health and safety measures, environmental briefings, big game movements, conduct of operations and storage were issued. These surveillances and field report (Appendix I, SPCO Surveillance Reports Issued in Fiscal Year 2009), are described in more detail below.

Milne Point Tour

On August 28, 2008, the Compliance Section staff (Team) arrived at the Milne Point Unit and participated in a safety orientation with a BP representative. The Team visited the control room and inspected the site where PHMSA jurisdiction of the Milne Point Pipeline begins at Module 58. The Team also toured the facility, including the pig launcher, Module 54 (gas compression module), and Module 57 (utility module).

All personnel encountered were wearing the appropriate personal protective equipment for the area in which they were working. Earplugs were available outside all areas marked as double hearing protection required. Good general housekeeping standards were also evident as the facility was toured.

The Team also drove the ROW to view the pig receiver and the Milne tie-in to the Kuparuk pipeline. The S-Pad Operator met the team at the Milne Pig Receiver module. The operator gave a brief tour of the pig receiver module and the generator module.

While driving the ROW caribou were observed on both sides of the pipeline. There was no evidence of blockage and the aboveground pipe appeared to meet elevation requirements and the ramps were in usable condition.

Fourteen surveillance reports were completed for the field trip. All found satisfactory conditions.

<u>SPCO Engineering Review: Milne Point Pipeline</u>
The NGL Milne Point Product Pipeline has been shut down and decommissioned. Only the Milne Oil Pipeline remains active. The major change to this pipeline is the replacement of approximately 1,200 feet of pipeline that was not piggable, because of the location of pigging facilities. BP replaced this section of pipe with duplex stainless steel pipe. SPCO Engineering has previous experience with this type of pipe; it is highly corrosion resistant, more so than even high grades of standard stainless steels, such as 316L.

The SPCO reviewed this project and monitored its progress. On a technical level, the project had no major incidents.

4.2.3.4 State Fire Marshall's Office

Annual Fire Prevention and Life Safety Inspections of the Milne Point facilities were conducted by the SFMO on January 11, 2009. Inspections covered both process and non-process areas. The inspections were successfully conducted with the help of BP Fire and Safety personnel and Milne Point Operations Personnel.

Twenty-three violations were found during the inspection of the facilities at Milne Point. Many of those violations were minor and were either corrected on the spot, or put on work orders or preventative maintenance schedules. In addition, there were no violations noted in the process areas reflecting BP's commitment to fire and life safety issues at Milne Point.

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4.2.4 Northstar Pipelines

Figure 60. *Northstar Pipelines origin at Seal Island.*

4.2.4.1 Right-of-Way Lease and Pipeline System Overview

The Northstar oilfield is located approximately 6 miles off of the Alaskan Beaufort Sea Coast, and approximately 11 miles northwest of Prudhoe Bay. Oil was originally discovered in the Northstar Unit by Shell in 1983 with exploration wells drilled from Seal Island. This manmade gravel island was built in 1982 in approximately 37-feet of water. It was later abandoned by Amerada Hess in 1994. BP acquired most of the Northstar Unit leases in 1995 and developed the field. Today BPXA operates dual 10-inch oil and gas pipelines that extend into the Beaufort Sea to the gravel island, referred to as Northstar Island by this report (Figure 60).

Produced crude oil is processed on Northstar Island and shipped via a trenched 10-inch oil pipeline to the shore, crossing at Point Storkersen, and then traveling an additional 11 miles overland to the TAPS PS 1. Natural gas is transported from the Prudhoe Bay Central Compressor Plant for approximately 16 miles to Northstar Island utilizing a second 10-inch pipeline that shares VSMs and a subsea trench with the oil pipeline.

The trenched pipes are designed and constructed to withstand potential seabed ice gouge and settlement loading conditions of thawed soils. The subsea section of the pipelines employs a leak detection system called LEOS, which is designed to sense hydrocarbon vapors in the soil surrounding the pipelines. This equipment is in addition to the oil pipeline's standard leak detection system, which monitors pressure, volume, and temperatures to detect releases. Both pipelines are piggable. Additional information regarding the physical parameters of the pipeline can be found in Appendix E, Physical Characteristics of SPCO Jurisdictional Pipelines.

The Northstar oil pipeline ROW Lease, ADL 415700, and the Northstar gas pipeline ROW Lease, ADL 415975, became effective on October 1, 1999, and expires on September 30, 2019 (Appendix G, Acreage, Survey, and Lease Information). A Release of Interest process for both ROWs was completed during this reporting period. The Release of Interest effectively reduces the original construction ROW width to a smaller operating width.

4.2.4.2 Annual Report

BPTA submitted its annual report to the SPCO on February 4, 2009, which presented information for seven pipelines, including the Northstar Pipelines. The report format paralleled the SPCO reporting requirements and met SPCO expectations, as set forth in Appendix J, SPCO Annual Reporting Requirements for Lessees, of this report. BPTA and the SPCO maintain communications and meet quarterly to discuss issues pertaining to the lease, including BPTA updates on activities and plans related to all BPTA pipelines (Appendix F, Lease Required Contact Information).

Significant items excerpted and extracted from the BPTA Annual Report regarding the Northstar Pipelines are presented below.

<u>Throughput, Pigging, and Reliability</u>
BPTA reported pipeline throughput and pigging activities in their 2008 annual report. This information has been summarized in Table 20. Throughput numbers for all SPCO jurisdictional pipelines can be found in Appendix K.

Table 20. Throughput and Pigging Information for Northstar Pipelines, 2008.

Pipeline System	2008 Throughput	MOP	Maintenance Pigging	Last ILI	Pipeline Operator
Northstar Oil	11,440,587 net barrels	1,480 psig at 100° F	Every 2 weeks	2006	BPXA
Northstar Gas	17,286,081 mscf.	1,480 psig	2 X year	2006	BPXA

Pigging
BPTA maintains a computerized maintenance management system for all of its fields that is designed to comply with the requirements of existing regulations. In 2008, PHMSA jurisdictional equipment was inspected and maintained. Cleaning/maintenance pig runs took place every two weeks for the oil pipeline. As part of the maintenance process the pig traps were coated.

Reliability
Northstar reported a total of three unscheduled shutdowns in 2008 in its annual report to the SPCO. Two of the unscheduled shutdowns have been reported to PHMSA as Abnormal Operating Conditions. These shutdowns include the following:

January 19, 2008: Stray voltage was inadvertently introduced into the control system that initiated a closure of the main pipeline valve located at the remote station. The valve closure caused an increase in pipeline pressure, resulting in a shutdown of the pipeline.

The pipeline valve was reopened after investigation showed that systems were normal at the remote station.

February 23, 2008: The Northstar oil transit pipeline had an unplanned shutdown. An electrical power interruption at TAPS PS 1 resulted in an increase in pressure in the Northstar oil transit pipeline to a point that activated the high-pressure shutdown switch. There was no oil spilled, no safety issues, no safety devices were activated, and the maximum pressure was below the maximum allowable operating pressure.

May 9, 2008: A loader operator clearing snowdrifts near Central Power Station (CPS) damaged an air line that is part of the power station's fuel control system. The damage interrupted fuel to CPS generators, which subsequently shut down Northstar's power generators. The facility and pipeline remained down for nine hours. This event was not reported as an Abnormal Operating Condition.

None of the pipeline shutdowns involved a hydrocarbon release.

Assurance Programs

DOT Integrity Management Program
Per 49 CFR Part 195.452, BPTA conducted a formal risk assessment of North Slope pipelines, including Northstar, on May 20, 2008. As part of the PHMSA-required pipeline IMP, the assessment identifies P&M measures. For Northstar two items were identified P&M measures (there was one in 2007 and 15 in 2006). The BPTA IMP assessment identified eight action items for 2008. The two P&Ms were; (1) Hire a DOT Coordinator, and (2) Develop a business resumption plan for the subsea portion of the Northstar Pipeline.

A Notice of Probable Violation was issued September 10, 2008 for lack of comprehensive internal corrosion control procedures, inadequate pipe coating to prevent atmospheric corrosion, and a missed mainline valve inspection.

Northstar experienced instances of PHMSA Abnormal Operating Conditions. Abnormal conditions are unintended or unexplainable events caused by the failure of operating equipment that result in exceeding the design limits of the pipeline system, but that are not events immediately identified as emergencies. These instances are described above in the Reliability section, and occurred on January 19, 2008 and February 23, 2008. None of the pipeline shutdowns resulted in a hydrocarbon release.

Quality Assurance
BPTA has a comprehensive QAP, approved by the State Pipeline Coordinator on December 21, 2004. The QAP is intended to protect the health and safety of employees, contractors, customers, the public, and others involved in the operation of the Northstar Pipelines and other facilities. The QAP is a requirement of the Northstar ROW Lease and, during 2008, BPTA personnel and the BPXA DOT Advisor made periodic visits to the North Slope to review compliance with state and USDOT regulatory requirements. The DOT Advisor also arranged DOT Training during two of the North Slope trips.

The BP Global Audit Team conducted an evaluation of all BPXA operations, North Slope and Anchorage in January 2008. This audit included the Northstar pipelines over which SPCO has the ROW authority. No results were shared in this annual report.

Personnel Safety Programs

Internal Safety Program

Each independent BPTA facility, including Northstar, takes ownership of their internal safety programs, whereby employees formally monitor each other's safety behavior. At Northstar, the internal safety program is called STOP. Employees at Northstar submitted 982 safety-related, or STOP, observations in 2008. These observations include items such as suggestions or positive reinforcement of observed good practices, as well as deficiencies. The effectiveness of the program is demonstrated by the safety statistics. For the last three years, Northstar has had no reportable OSHA days away from work, OSHA recordable accidents/incidents, OSHA first aid, or major incident reports for pipelines.

External Safety Program

BPXA employs various contractors for work on the Northstar ROW. Contractor safety is managed by BPXA's Internal Safety Program. At Northstar, the contractors actively participated in the STOP program and were observed by supervisors, as described above in the Internal Safety Programs section. Contractors were also accounted for in the safety statistics listed above.

BPXA has other safety controls for large projects and work that is not day-to-day at Northstar. The Authorization to Proceed process is used to ensure safety controls are in place before work is started. The Authorization to Proceed is approved by the BPXA Operations Supervisor, BPXA HSE Representative, Contract Project Lead, Project Manager, and Job Supervisor. Task Hazard Analyses are conducted to gather information for employee protection. The Task Hazard Analyses Database serves as a repository for frequent tasks.

Corrosion Program

Cathodic Protection Survey - The CP annual monitoring of the offshore pipelines took place in September 2008. BPTA noted that structure-to-electrolyte potentials were measured at either end of the pipelines and met the requirements of 49 CFR 192 and 195. The results are based primarily on portable reference electrode measurements.

All BPXA pipelines are on a 3-year ILI schedule. According to the BPXA Annual Report submitted to the SPCO, an ILI was to be conducted in 2009 on the Northstar pipelines.

A cathodic protection survey was completed at the river crossings in September 2008.

Other Risk Management Programs

The BPXA's North Slope Oil Spill Contingency Plans have been approved both by DEC and PHMSA. Contingency actions at Northstar included placing spill response materials near the pipeline "log cabin" on the production island and at the shore crossing.

In 2008, BPTA sent Non-readiness Notifications to DEC per their Oil Discharge Prevention and Contingency Plan requirements. Non-readiness Notifications are required when spill response equipment is not available or a significant change occurs in pipeline leak detection and it no longer meets DEC regulatory requirements. During 2008, the following Non-readiness Notifications associated with the ROWs and PHMSA pipeline activities were made:

- January 21, 2008: Northstar shutdown the LEOS system for maintenance. The Primary leak detection system was working as designed. The maintenance work required a 12-hour vacuum purge of the LEOS tube.
- March 4, 2008: There was a false indication of a LEOS Leak Alarm. Data was sent to out for data interpretation. It was determined this false indication was due to a brief loss of power to the temperature controllers.

Surveillance & Monitoring Programs

Aerial Surveys
Shared Services Aviation conducted 53 PHMSA required aerial inspections of the Northstar ROW in 2008. No issues were observed. One of these over-flights included FLIR assessments.

Ground Surveys
The annual, PHMSA-required, walking-speed ground survey of the above-ground pipe includes extensive visual inspections. These surveys, and any follow-up work requirements, are conducted primarily to satisfy PHMSA requirements. However, PHMSA often coordinates and cooperates with the SPCO. Visual inspections of the sales oil and gas pipelines took place April 1-8, 2008. These inspections were completed using tracked vehicles and by walking the pipeline ROW from Point Storkersen to PS 1. Two sheet metal jacket perforations were noted on the gas line and two perforations and missing sheet metal with stripped insulation were noted on the sales oil pipeline. The Northstar maintenance team was to follow up on surveillance items through their work order system.

Other Northstar Monitoring

Northstar Shoreline Crossing
A significant storm struck in July 2008 raising water levels to a high not seen since 2000. While annual shoreline monitoring showed some recession of the bluff, BPXA determined that no erosion mitigation measures were required due to the pipeline pad set-back distance and history of modest erosion rate. The Northstar Pipeline Shore Crossing landfall (Point Storkersen) has been the site of an annual rehabilitation effort to control erosion since Northstar was constructed during the winter 1999/2000. The focus of the project has been erosion control and stabilizing the trench backfill. For the second year, the inspection noted that a section of the erosion control matting near the northwest end of the backfill was displaced. The recommendation is to place additional bio-netting or other material at the site to prevent further disturbance.

Subsea Pipeline Route Monitoring

For the ninth year, the pipeline route from the Northstar Production Island to the shore transition was monitored for ice gouging, strudel scour, ice wallows, and subsidence. *(Strudel scour is a seasonal event where fresh water melt during the spring moves out over sea ice and pushes down through sea ice. The melt creates a whirlpool effect that can churn depressions into the sea floor. Ice wallows are shallow depressions in the sea floor created by the keels of grounded ice floes and in-place agitation by waves, currents, or other ice. These processes can expose areas of the buried pipe crossing over to the production island.)* This year's monitoring noted that the pipeline alignment for 2008 was similar to alignment conditions in 2007. The monitoring also revealed the following items of interest:

Subsea Pipeline Route Monitoring - Subsidence

Subsidence in 12 areas along the pipeline route – five of those areas represent an increase over subsidence noted the previous year. One area of subsidence caused a decrease in the backfill thickness below the required six feet minimum. Fifteen-hundred cubic yards of gravel was barged to the site to fill the subsidence depression.

Subsea Pipeline Route Monitoring - Ice gouges

Sixteen ice gouges were detected on the pipeline route. Twelve of the gouges represented newly discovered features, while four were relict gouges that had been discovered during prior surveys. The frequency and severity of gouging were low by historical standards. Of particular note is the maximum incision depth of 1.0 feet, which represents the lowest such value recorded since monitoring of the pipeline alignment was initiated in 2000.

Subsea Pipeline Route Monitoring - Ice Wallows

One new ice wallow was identified on the pipeline route in 2008 along with one relict wallow from 2007. The discovery of the new wallow represents the third time in nine years that such features have been noted in the Northstar project area.

Subsea Pipeline Route Monitoring - Strudel Scour

The 2008 Kuparuk River overflood was substantially smaller than that noted in any of the prior eight years. Most of the flood water was confined to the immediate vicinity of the river's mouth. During the prior eight years, the number of drains detected in the 4,000-ft corridor ranged from eight to 62, averaging 34 per year. All 19 drainage features in 2008 were circular or oblong in plan form, with estimated diameters ranging from two to 25 feet.

Shallow water depth prevailed at each of the 19 locations where drainage features were observed in the ice during the river overflood period. No (strudel) scour depressions were found in any of the search areas. This absence of newly–discovered strudel scours is unprecedented since the initiation of data acquisition in 2000.

Thermistor Data

Thermistor readings are one type of permafrost monitoring conducted by BPXA at Northstar. There is a concern that an increase in the oil line's thaw bulb may cause slumping of the crossing's tundra edges perpendicular to the shore. Thermistor readings at the shore crossing were attempted in October 2008. It was observed that some of the thermistor wires had been damaged. The partial readings indicate thaw bulb growth beyond the excavated trench.

Coastal Stability Monitoring
Shore crossing ground surveys are conducted annually on Northstar. Mitigation would be triggered if the bluff recession analyses indicated the need. The annual evaluation of bluff erosion is required by the Department of the Army Permit N-950372, Special Condition #2 (issued to BPXA in May 1999). According the BPXA 2008 report, the toe of the pipeline shore pad lies about 72 feet landward of the eroding backfill face and the pipeline riser is more than 135 feet from the Mean Lower Low Water shoreline. Given this set-back distance from the eroding coast and the modest historical erosion rate, no erosion mitigation measures are required at this time.

<u>2008 Activities</u>

Construction Activities
No construction was conducted on the Northstar Pipelines during 2008.

Maintenance Activities
BPTA maintains a computerized maintenance management system for all of its fields designed to comply with the requirements of existing regulation. 2008 maintenance activities at Northstar included the following:

- PHMSA jurisdictional equipment was inspected and maintained in 2008.
- Cleaning/maintenance pig runs were conducted approximately every two weeks for the Sales Oil Pipeline.
- Pig traps were painted and coated.
- Missing sheet metal and sheet metal perforations were repaired.
- Gravel berm maintenance was performed by removing gravel to the original permitted depth (16 feet below water level) and relocating it over pipeline areas where subsidence had resulted in less than eight feet of cover.
- Annual Corrosion Monitoring completed for pipeline above to below ground transition at "log cabin" island vault.
- CP Survey was conducted in September 2008.
- 1,500 cubic yards of gravel was placed between Stations 184+02 and 187+05 to fill a subsea subsidence depression.

2009 Proposed Actions and Plans

The planned 2009 internal BPXA activities are listed below in Table 21.

Table 21. Table of Proposed Actions and Plans, Northstar Pipelines

Quarter /Activity	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Aerial Inspections Every Two-Weeks	✓	✓	✓	✓
Cleaning/ Maintenance Pig on the Sales Oil Line	✓	✓	✓	✓
Smart Pig runs for Oil and Gas lines		✓		
Ground Survey		✓		
Bathymetry Survey for Strudel Scour and Ice Gouging			✓	
Thermistor readings and repairs	✓			
Annual Corrosion Monitoring in "log cabin" island vault				✓
Cathodic Protection Survey		✓		
Risk Assessment Review of the Sales Oil Pipeline (DOT IMP)		✓		

Based on the assessment of the Northstar shoreline where the pipeline transitions aboveground we anticipate that additional bio-netting or other material will be installed at the site in 2009 to prevent further disturbance. There is also a Work Order to repair damaged thermistor wires.

4.2.4.3 Oversight Activities of the State Pipeline Coordinator's Office

(*This section provides a summary of SPCO activities. Information in this section reflects the work efforts of the State Pipeline Coordinator's Office and is not taken from the Lessee's annual report. By the nature of the SPCO work, there will be some overlap of information.)*

Lease Compliance

During the FY09 reporting period, SPCO Lease Compliance staff completed four surveillance reports. All four surveillance reports contained satisfactory lease compliance observations. Lease Compliance staff also performed an aerial survey of the Northstar pipelines during this reporting period, but reported on that survey in the FY10 reporting period.

SPCO Right-of-Way Section

Construction ROW Releases of Interests

On October 1, 2008, the SPCO sent a letter to BPTA transmitting Executed Release of Certain Interests in Lands for Northstar Oil (ADL 415700) and Gas Pipeline (ADL 415975) Right-of-Way Leases documents. The letter also provided a copy of the Analysis and Recommendations of Release of Interests in Northstar Pipelines'

Construction Rights-of Way. A field inspection and a records review indicated the absence of disturbed state lands that required stabilizing, revegetation, or restoration within the construction right-of-way and verified that previously disturbed lands had been restored and in acceptable condition.

A release of interests in the construction ROW effectively reduces the right-of-way to the width necessary for pipeline operation and maintenance. The Record of Survey, EPF 20020017, containing 419.13 acres for the Northstar Oil Pipeline ROW and 405.51 acres for the Northstar Gas Pipeline ROW, describes the operation and maintenance area of each pipeline right-of-way. The Release of Interest reduced the total combined acreage of both ROWs by nearly 2,800 acres. The Release of Certain Interests document was recorded on October 20, 2008, in the Barrow Recording District.

<u>SPCO Engineering Report: Northstar Pipelines</u>
Northstar was the first operational offshore oil field development in the Arctic and the first to use subsea pipelines in the Arctic on an operational basis. The project faced many technical challenges. The Northstar Project Final Environmental Impact Statement and the State ROW Lease were issued in 1999. Seal Island was rebuilt and enlarged between January and May 2000.

Dual 10-inch oil and gas pipelines extending offshore to the gravel island are designed and constructed to withstand potential seabed ice gouging and permafrost thaw settlement loading conditions. These design requirements were addressed by using limit states bending analysis to ensure the integrity of the pipelines during their service life.

During CY08 there were no major incidents reported for the Northstar Pipelines. Aerial and ground surveillances of the onshore portion found no significant pipeline problems or surface disturbances on the cross-tundra segment. The subsea pipeline and the shore transition at Pt. Storkersen were designed for subsidence and observed changes are within the design allowables.

It was noted, however, that the Lease Design Basis and other documents were not in complete agreement with the existing pipeline design at the Pt. Storkersen. To remedy this, BP submitted as-builts of this area, as well as a revised stress analysis indicating that the pipeline was still within code allowable stress and strain levels.

4.2.4.4 State Fire Marshal's Office
Annual Fire Prevention and Life Safety Inspections of the Northstar facilities were conducted by of the Alaska Division of Fire and Life Safety on October 22, 2008. The inspections covered numerous process and non-process facilities. The inspections were successfully conducted with the help of BP Fire and Safety Personnel and Northstar Operations Personnel.

Five violations were found during the inspection Northstar facilities. Most the violations noted during the inspection were either corrected on the spot, or put on work orders or preventative maintenance.

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4.3 Nuiqsut Natural Gas Pipeline

Figure 61. *NNGP Operations building housing control center, valve room, pig launcher/receiver.*

4.3.1 Right-of-Way Lease and Pipeline System Overview

The Nuiqsut Natural Gas Pipeline (NNGP) was constructed by the NSB to transport natural gas from the ConocoPhillips Alpine Production pad to the village of Nuiqsut, located within the Colville River Delta. The 14.4-mile NNGP shares horizontal and vertical supports with the Alpine Pipelines from the production pad to the west bank of the Colville River. There the NNGP transitions belowground (Figure 62) and continues to the village. Approximately 2.4 miles of the 14.4-mile NNGP are located on state land, a section of the aboveground pipeline and the trenched crossing of the Nechelik Channel of the Colville River.

Figure 62. *Point where NNGP transitions from aboveground to belowground.*

The NNGP is a three and one-half inch diameter coiled tubing pipeline with a wall thickness of 0.203 inches designed to operate at 1,440 psig. The NNGP was supplied with an external coating applied at the factory. A continuous magnesium strip cathodic protection system was installed on the belowground portion of the NNGP. The pipeline is subject to PHMSA jurisdiction and operates under 49 CFR 192 regulatory requirements.

The pipeline project began in 1999 and construction was completed soon after. Operational startup of the pipeline was delayed for eight years. Pipeline operation began in 2008 and will deliver natural gas for heating and production of electricity to the community of approximately 380 residents. This will dramatically reduce energy costs for this remote Alaskan community. Once the system is fully operational, Nuiqsut will become the third North Slope community (after Barrow and Deadhorse) to provide heat and generate electricity from natural gas.

The NNGP ROW lease, ADL 416202, was executed on March 15, 1999 and is scheduled to expire on March 14, 2019. The pipeline operational ROW width is 50 feet in the aboveground mode and 200 feet at the river crossing. The ROW as-built survey was approved by DNR on December 17, 2003; it encompasses 17.67 acres of state lands. Additional lease information is available in Appendix G, Acreage, Survey, and Lease Information. The NNGP is due for reappraisal in 2014 (Appendix H, Pipeline ROW Lease Appraisal Information).

4.3.2 Annual Report

The NSB submitted their 2008 annual report to the SPCO on March 3, 2009. The NSB received two minor unsatisfactory observations in the surveillance of their 2008 annual report, enclosed with SPCO letter 09-015-CT. The report was submitted late and the results of the SMP were not included in the annual report. Throughput and Pigging information are summarized below in Table 22. Appendix K provides a listing of throughput for all SPCO jurisdictional pipelines.

Table 22. Throughput and Pigging Information for NNGP, 2008.

Pipeline System	2008 Throughput	Maximum flow rate	MAOP	Maintenance Pigging	Last ILI	Pipeline Operator
NNGP	16,976.36 mcf	3,500,000 cu ft/day	1,440 psig	2008	Hydrostatic Test April 2007	Rockford

Lease section eight and each stipulation were addressed in the annual report in an effort to illustrate performance under the lease as required by Lease stipulation 1.14.1 (3). No construction activities were performed during the reporting period. There were no spills or accidents reported in 2008.

Prior to start-up and commissioning all systems were confirmed to be tested and ready for service. Commissioning was reported as being completed in September 2008. Additional information provided by the NSB included the submittal of the 2006 Annual Report to the SPCO on April 25, 2008 and the 2007 Annual Report on May 7, 2008. A revised SMP was submitted on June 2, 2008 and was approved by the SPCO on

June 6, 2008. Efforts between the North Slope Borough and the SPCO for a QAP are ongoing.

While routine surveillance and monitoring activities were not documented in the report, the detailed accounting of work conducted in support of commissioning and start-up was appreciated. A contractor for the NSB inspected the aboveground portions of NNGP from April 3-9, 2008. The contractor visually inspected the NNGP under American Petroleum Institute 570 guidelines. Coating damage at supports and isolated support failure in intermediate supports were identified. The contractor also inspected, for corrosion using non-destructive ultra sonic testing. No areas of corrosion or wall loss were identified. Non-destructive magnetic partical testing was used to inspect for cracking, no areas of stress or cracking were found.

4.3.3 Oversight Activities of the State Pipeline Coordinator's Office

(*This section provides a summary of SPCO activities. Information in this section reflects the work efforts of the State Pipeline Coordinator's Office and is not taken from the Lessee's annual report. By the nature of the SPCO work, there will be some overlap of information.)*

<u>SPCO Engineering Report: Nuiqsut Natural Gas Pipeline</u>
The NNGP started taking gas from Alpine June 16, 2008. Although this occurred immediately prior to the start of the state fiscal year, startup is included in this report because it was essentially a phased start, with ongoing activities extending throughout the reporting period.

During startup, the pipeline was pressured up. However, an engineering consultant for NNGP reported that natural gas in quantity did not start to flow through the pipeline for several months. The primary use of natural gas in Nuiqsut is to heat buildings and generate electrical power. The effort to convert heating appliances to natural gas began months after pipeline startup. The new natural gas engine electrical generators had to be modified and their reliability improved. They could only be fully tested once natural gas was available. Until the generators reliability was improved, the community relied on diesel generators. As more and more gas fired equipment came on line, natural gas use and transportation rates increased gradually during the reporting period.

The Nuiqsut pipeline was started up approximately eight years after its original construction. SPCO Engineering's research indicates that this is an unprecedented period between construction and operation. The high asset value of pipelines typically results in startup as soon as practicable, after mechanical completion. Because of this, the condition of the pipeline was a subject of discussion. In the intervening years, remedial work had to be performed at a river crossing and external coating damage was identified. The SPCO requested that a sample of the external coating anomalies be inspected and a report on the corrosion and readiness of the pipeline be prepared by a professional engineer. The report concluded that the pipeline corrosion was nominal, and therefore startup could be performed under acceptable safety conditions.

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5.0 The Climate Change Technical Working Group

Former Governor Palin signed Administrative Order 238, creating the Climate Change Sub-Cabinet on September 14, 2007. AO 238 can be downloaded from the following website:

http://www.gov.state.ak.us/admin-orders/238.html

The State Pipeline Coordinator's Office provided a member to the Alaska Climate Change Strategy Technical Working Group. This group was composed of representatives from the state, oil companies, refiners, service companies, and other areas. The group was the Oil and Gas Technical Working Group. This was one of several advisory groups that developed information and analysis for the Mitigation Advisory Group (MAG). The MAG, in turn, reported to the Governor's Sub-Cabinet on Climate Change. The Sub-Cabinet advises the Office of the Governor on the preparation and implementation of an Alaska climate change strategy.

The following web page describes the State of Alaska's efforts in this area. Refer to it for further information on the intent and policies of the group:

http://www.climatechange.alaska.gov/

The work and the recommendations of the Oil and Gas Technical Working Group can be downloaded as Chapter 6 in the report, at the following website:

http://www.akclimatechange.us/Mitigation.cfm

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6.0 OUTLOOK FOR FISCAL YEAR 2010

The SPCO will continue to pursue its mission in FY10. Coordination with federal agencies within the JPO remains an important factor in providing efficient oversight of jurisdictional pipelines. The JPO agencies continue to adhere to the provisions of the Operational Agreement that came into effect prior to the release of last year's SPCO FY09 annual report. The agreement aids the SPCO in achieving its missions and goals, which include:

SPCO Mission

- Process applications under the Alaska Lands Act and Right-of-Way Leasing Act and negotiate and deliver pipeline and other ROW leases in a manner that serves the State's interests.
- Administer leases under SPCO jurisdiction including revenue, permitting, authorizations, and oversight of the construction, operation, maintenance, and termination of pipelines on State leased land.
- Coordinate SPCO TAPS Lease oversight with state and federal agencies to ensure that TAPS remains available for delivery of North Slope crude oil to marketplace, and
- Keep the public informed of SPCO activities.

General FY10 Goals

- Maintain an adequate workforce to deliver essential services, including but not limited to, assessment of pipeline ROW lease compliance, pipeline ROW issuance and amendments, and engineering reviews.
- Thorough regulatory and lease compliance oversight, minimize pipeline shutdowns and environmental hazards.
- Coordinate pipeline permitting and oversight with other state and federal agencies.

In addition to the mission and goals described above, the SPCO FY10 work efforts, including ongoing regulatory and lease administration activities, will focus on:

Gas Pipeline Efforts

The SPCO has entered into reimbursable service agreements with three project proponents involved with projects aimed at developing Alaska's natural gas reserves. These project proponents are TransCanada Alaska Company, LLC, Denali - The Alaska Gas Pipeline, LLC and the Alaska Natural Gas Development Authority (ANGDA). These agreements allow state agencies to be reimbursed for their work associated with the pre-application phase of developing a right-of-way lease. The SPCO anticipates a similar arrangement will exist shortly with the Stand Alone Gas Pipeline System, a State sponsored project to obtain a small diameter pipeline ROW from the North Slope to Southcentral Alaska.

The SPCO is also working on a similar agreement with ExxonMobil to coordinate the State's permitting efforts for a proposed pipeline ROW from the Point Thomson Unit to Prudhoe Bay.

In addition, the SPCO anticipates two new natural gas pipeline projects on the Kenai Peninsula may begin the AS 38.35 permitting process in FY10. Anchor Point Energy, LLC has announced plans to build a pipeline to transport natural gas from the North Fork Unit to the town of Anchor Point. In conjunction with the Anchor Point Energy project, ENSTAR proposes to construct a pipeline from the town of Anchor Point to Ninilchik and tie-in to the Kenai-Kachemak Pipeline System.

Trans-Alaska Pipeline System:
APSC is engaged in efforts to complete SR of key pump stations and facilities to provide the TAPS with greater operational flexibility as the throughput continues to decline. Most of SR has been completed, but there is still significant work remaining to complete modifications to SR stations as part of the EA program. SPCO agencies will continue to monitor this activity.

The SPCO engineering section will closely monitor efforts by APSC to study the implications and potential future impacts to TAPS resulting from decreased throughput. They believe that decreased volumes of oil in the pipeline will create challenges involving: ice formation, paraffin build-up, viscosity, and gelling issues. The engineering section also plans to monitor efforts by APSC to improve elements of its TAPS integrity program relating to developments for internal inspections and monitoring of pipeline conditions involving ILI (smart pigging and similar devices) and efforts by APSC to survey and evaluate the condition and elevation of the FGL through the use of geopigging and LIDAR technology.

SPCO staff will also work closely with APSC officials to follow up on recommended actions to ensure that identified corrective actions in response to the January 2009 PS 1 hydrocarbon discharge are implemented.

Non-TAPS Jurisdictional Pipelines:
SPCO staff will continue to monitor lessee compliance with pipeline ROW lease conditions and stipulations. All jurisdictional pipelines will see some level of ongoing assessment and surveillance work, as well as a focus on special projects or issues as assigned by the State Pipeline Coordinator.

7.0 APPENDICES

Appendix A - FY09 Annual Report Major Source Documents

1. APSC, "Trans Alaska Pipeline System (TAPS) 2008 Annual Report: TAPS Valve Program". Government Letter No. 18203, March 31, 2009.
2. APSC, "Alyeska Compliance Program Monitoring and Performance Report: 2008". Government Letter No. 19038, July 22, 2009.
3. APSC, "Trans Alaska Pipeline System (TAPS) 2008 Annual Report: Mainline Aboveground Support System and Bridges Program". Government Letter No. 18322, April 17, 2009.
4. APSC, "Trans Alaska Pipeline System (TAPS) 2008 Annual Report: Right-of-Way and Facilities Civil Monitoring Program". Government Letter No. 18322, April 17, 2009.
5. APSC, "Trans Alaska Pipeline System (TAPS) 2008 Annual Report: Pipeline and Valdez Marine Terminal Facilities Corrosion Monitoring". Government Letter No. 18322, April 17, 2009.
6. APSC, "Trans Alaska Pipeline System (TAPS) 2008 Annual Report: Fuel Gas Line". Government Letter No. 18322, April 17, 2009.
7. APSC, "Trans Alaska Pipeline System (TAPS) 2008 Annual Report: Mainline Integrity Monitoring". Government Letter No. 18322, April 17, 2009.
8. APSC, "Trans Alaska Pipeline System (TAPS) 2008 Annual Report: Rivers, Floodplains & Glacier Monitoring Program". Government Letter No. 18322, April 17, 2009.
9. APSC. "Trans Alaska Pipeline System (TAPS) 2008 Annual Report: Tank Monitoring". Government Letter No. 18322, April 17, 2009.
10. BPTA, "2008 Annual Surveillance and Monitoring Report for ADNR, Vol. 1."
11. BPTA, "2008 Annual Surveillance and Monitoring Report for ADNR, Vol. 2, Badami Background Information".
12. BPTA, "2008 Annual Surveillance and Monitoring Report for ADNR, Vol. 3, Endicott Background Information".
13. BPTA, "2008 Annual Surveillance and Monitoring Report for ADNR, Vol. 4, Milne Point Background Information".
14. BPTA, "2008 Annual Surveillance and Monitoring Report for ADNR, Vol. 5, Northstar Background Information".
15. ConocoPhillips, "2008 Annual Comprehensive Report on Pipeline Activities, Volumes. I and II, Alpine Oil Pipeline ADL 415701, Alpine Utility Pipeline ADL 415857, and Alpine Diesel Pipeline ADL415932".
16. OPC, "2008 Annual Comprehensive Report on Pipeline Activities, Volumes. I and II, Oliktok Pipeline ADL 411731".

17. KTC, "2008 Annual Comprehensive Report on Pipeline Activities, Volumes. I and II, Kuparuk Pipeline ADL 402294 and Kuparuk Pipeline Extension ADL 409027".

18. Marathon Pipe Line Company, LLC, "Kenai Kachemak Pipeline 2008 Annual Report," January 30. 2009 (Amended March 17, 2009).

19. Tesoro Alaska Pipeline Company, LLC, "Revision 2008 Annual Comprehensive Report on Pipeline Activities and State of the Pipeline System, Tesoro Alaska Pipeline Company (Nikiski) Right-of-Way Lease – ADL 69354", January 29. 2009.

20. NSB, "Nuiqsut Natural Gas Pipeline ADL 416202 Annual Comprehensive Report: On Pipeline Activities and the State of the Pipeline System". March 3, 2009.

21. AREVA NP GMbH, "LEOS Northstar; Functional Leak Simulation Test 2008, STD1-G/2008/en/0039 Rev. A".

22. APSC, "Low Throughput and Cold Restart Impacts". Presentation, March 12, 2007.

23. APSC, "TAPS Low Flow Impact Study, JPO Discussion", Presentation, June 2009.

24. TAPS Owners, "Summary: A Report on Low Flow Issues Through 2030, JPO Discussion", http://www.taps-flow.com/Docs/TAPS-Flow Exec Summary.pdf, 3 June 2009.

25. TAPS Owners Committee, "TAPS Low Throughput Issues", "Full Presentation", at http://www.taps-flow.com, October 1, 2008.

26. 25. APSC, "Request for Information Relevant to Turbine and Diesel Generator Reliability at PS 3 , PS 4, and PS 9". Government Letter No. 19748, November 3, 2009.

27. APSC Event Notification forms provided by OCC between March 1, 2008 and June 30, 2009.

28. SPCO Letter No. 08-043-CT, Surveillance of the Kenai Kachemak Pipeline (ADL 228162), June 26, 2008, August 5, 2008.

29. SPCO Letter No. 08-113-TG, Kuparuk Pipeline Extension Right-of-Way Lease, ADL 409027, SPCO Authorization under Stipulation 1.7.1 for Kuparuk Pipeline Extension Pipeline Replacement Project, November 28, 2008.

30. SPCO Letter No. 08-117-TG, Transmittal of Executed Release of Certain Interests in Lands for Kenai Kachemak Pipeline (ADL 228162) Right-of-Way Lease, December 10, 2008.

31. SPCO Letter No. 09-001-CT, SPCO August 28, 2008 Surveillance of the Kuparuk (ADL 402294), Kuparuk Extension (ADL 409027), and Oliktok (ADL 411731) Pipelines, February 20, 2009.

32. SPCO Letter No. 09-002-CT, Transmittal of SPCO Field Report, Nikiski Alaska Pipeline (ADL 69354) Observations of Tesoro Cathodic Protection Project - Drilling Phase, April 2008, January 26, 2009.

33. SPCO Letter No. 09-003-CT, SPCO Request for Additional Information for the 2008 Annual Comprehensive Report of Pipeline Activities and State of the Pipeline

System, Tesoro Alaska Pipeline Company (Nikiski ROW Lease, ADL 69354), February 23, 2009.

34. SPCO Letter No. 09-011-WW, SPCO Review of the Kenai Kachemak Pipeline 2008 Annual Report, March 10, 2009.

35. SPCO Letter No. 09-015-CT, SPCO Review of the (2008) Annual Comprehensive Report on Pipeline Activities and the State of the Pipeline System for the Nuiqsut Natural Gas Pipeline (ADL 416202), April 8, 2009.

36. SPCO Letter No. 09-017-CT, SPCO Review of Tesoro's Addendum to the 2008 Annual Comprehensive Report on Pipeline Activities and State of the Pipeline System for the Nikiski Alaska Pipeline, April 14, 2009.

37. SPCO Letter No. 09-027-TG, Badami Sales Oil Pipeline Right-of-Way Lease, ADL 415472 and Badami Utility Pipeline Right-of-Way Lease, ADL 415965, Badami Weir - Phase 2 Civil Scope of Work, Issued for Construction Report, March 4, 2009.

38. SPCO Letter No. 09-028-CT, SPCO Surveillance of the Nikiski Alaska Pipeline (ADL 69354) on June 1,2009, July 1, 2009.

39. SPCO Letter No. 09-081-TG, Acceptance of Unconditional Guaranty of Chevron Corporation for Kenai Kachemak Pipeline Right-of-Way Lease (ADL 228162), June 29, 2009.

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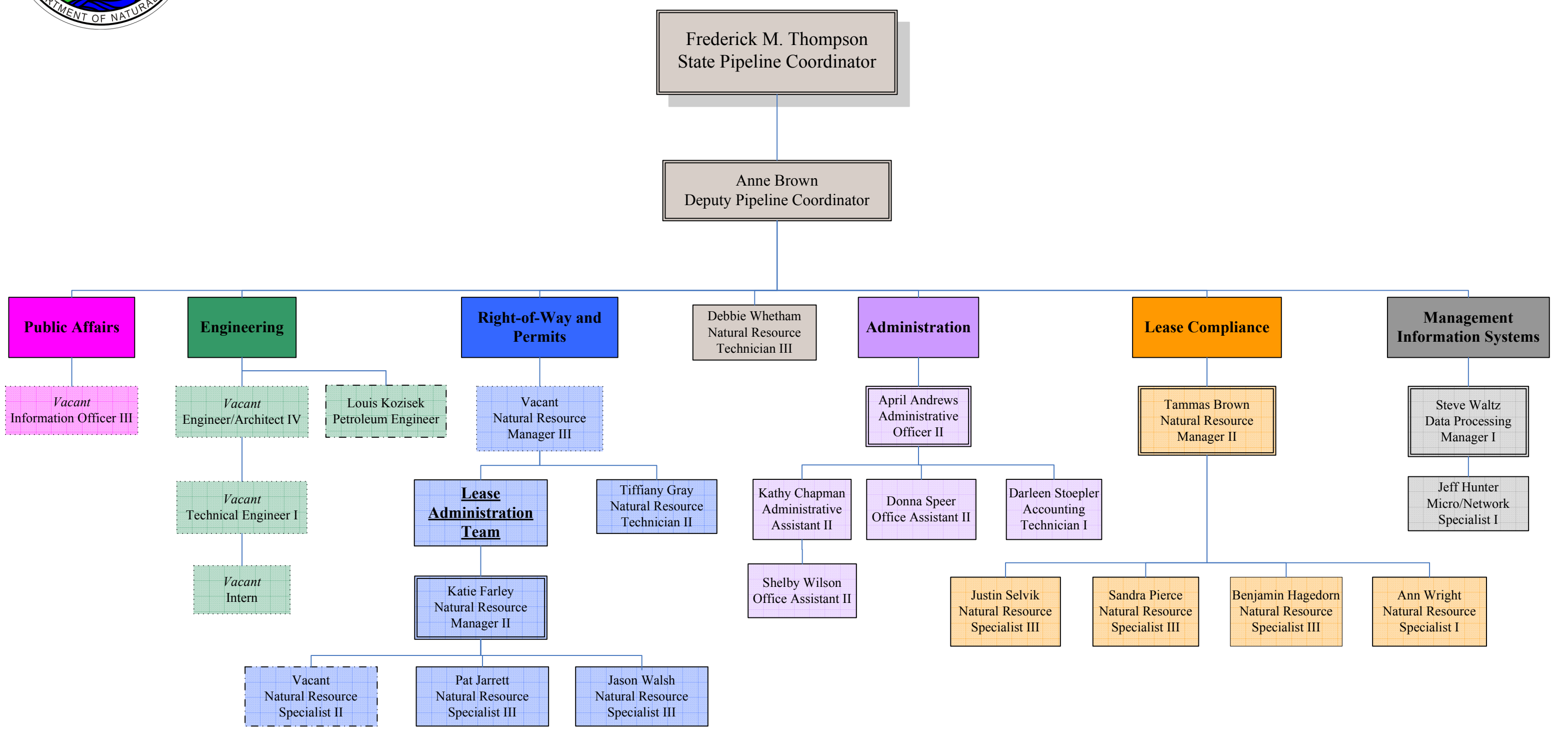
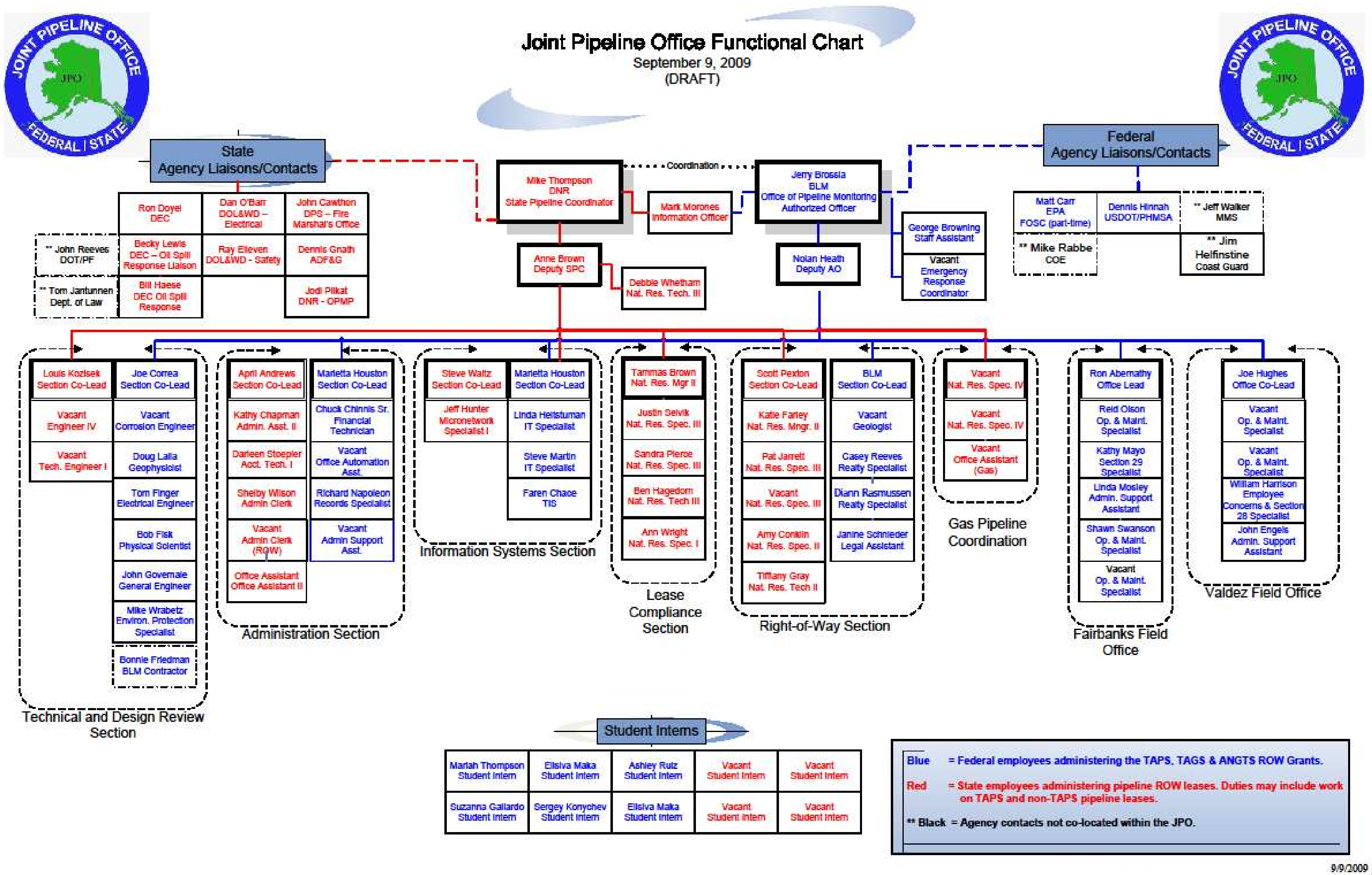
Appendix B – SPCO Staff Organizational Chart

State Pipeline Coordinator's Office Staff Resources



Appendix C – Joint Pipeline Office, (draft) Organizational Chart



Appendix D - Authorizations, Rights-of-Way, and Permits Issued, by Quarter

First Quarter FY09: July 01, 2008 – September 30, 2008

Permit / ADL Number	Date	Location	Description
Temporary Water Use Permit (TWUP) P2008-2	7/18/2008	Sec*. 26, T. 7 S, R. 1 W, CRM AK	A TWUP was issued to withdraw up to 35,000 gallons of water per day from a pond between PLMP 757 and Richardson Highway MP 42.5 for Pad Maintenance & Dust Suppression activities between PLMP 750 and 765. The pond is located within Section 26, Township 7 South, Range 1 West, CRM, AK. (20080722-12)
TWUP P2008-1 Amendment No. 1	7/22/2008	Sec. 7, T. 1 N., R. 15 E., UM, AK	An existing TWUP was amended to include two additional water take locations because of low flow conditions in the Sagavanirktok River. The two additional locations are: PS 2 Threaded O-Ring (TOR) Manhole and PS 2 LEFM Utilidor. (20081002-12)
LAS 26494	7/30/2008	Sec. 6, T. 4 S, R. 14 E, UM, AK	A Land Use Permit (LUP) containing approximately 2.0 acres was issued to reestablish the earthen cover on the former non-hazardous SWD Site 124-1 located adjacent to Dalton Highway Milepost 333, to prevent further degradation of the ground surface and further exposure of waste material to wind and water erosion.
ADL 230460	7/30/2008	Sec. 28, T. 9 S, R. 4 W, CRM, AK	A material sale contract was issued at OMS 3-2 to remove 6,000 cubic yards of sandy fine to course gravel with some cobbles and a trace of silt. The material site consists of approximately 55.0 acres.
LAS 26919	9/3/2008	Sec 31, T. 14 S, R. 10 E, FM, AK	A LUP containing approximately 5.0 acres was issued for storage of mineral material and non-toxic, non-hazardous TAPS materials and equipment at OMS 41-1R.
LAS 26922	9/3/2008	Sec. 8, T. 6 N, R. 4 W, FM, AK	A LUP containing approximately 5.0 acres was issued for storage of mineral material and non-toxic, non-hazardous TAPS materials and equipment at OMS 68-1.
LAS 26923	9/3/2008	Sec. 15, T. 7 N, R. 4 W, FM, AK.	A LUP containing approximately 5.0 acres was issued for storage of mineral material and non-toxic, non-hazardous TAPS materials and equipment at OMS 68-4.
LAS 26925	9/3/2008	Sec.33, T. 10 N, R. 7 W, FM, AK	A LUP containing approximately 5.0 acres was issued for storage of mineral material and non-toxic, non-hazardous TAPS materials and equipment at OMS 73-1R.
LAS 26926	9/3/2008	Sec. 35, T. 29 N, R. 12 W, FM, AK	A LUP containing approximately 5.0 acres was issued for storage of mineral material and non-toxic, non-hazardous TAPS materials and equipment at OMS 98-3.1.
TWUP P2008-3	9/10/2008	Sec. 29, T. 3 N, R. 1 W, CRM, AK	A TWUP was issued to withdraw 35,000 gallons of water per day from a pond at PLMP 691.5 for pad maintenance and dust suppression between PLMP 688 and 697. (20080912-2)
TWUP P2008-4	9/11/2008	Sec. 5, T. 8 S, R. 1 W, CRM, AK	A TWUP was issued to withdraw 750,000 gallons of water per day from Cascade Chute for dewatering a pipeline integrity investigation at PLMP 761.73. (20080912-3)
LAS 27039	9/23/2008	Sec. 5 and 8, T. 6 N, R. 4 W, FM, AK	A LUP containing approximately 0.25 acres was issued for replacing an existing culvert across the TAPS work pad at PLMP 408.4 also known as Slate Creek.
TWUP P2008-2 Amendment No. 1	9/24/2008	Sec. 26, T. 7 S, R. 1 W, CRM, AK	An existing TWUP was amended to correct the legal description and the expiration date of the original permit. The location was corrected from NW4SW4 to the SW4NW4, Section 26, Township 7 South, Range 1 West, CRM, AK. The expiration date was corrected from September 31, 2012 to September 30, 2012.
TWUP P2008-4 Amendment No. 1	9/29/2008	Sec. 5, T. 8 S, R. 1 W, CRM, AK	An existing TWUP was amended to extend the effective date of the original permit from September 30, 2008 to October 31, 2008. (20080930-7)

*Section = Sec.	Township = T.	South = S	North = N	Range = R.	East = E	West = W	Copper River = CR	Fairbanks = F	Umiat = U	Meridian = M

Second Quarter FY08: October 1, 2008 – December 31, 2008

Permit / ADL Number	Date	Location	Description
ADL 415700 ADL 415975 Release of Interests	10/1/2008	Record of Survey, EPF 20020017	Lessee BPTA released/conveyed to the State those lands encumbered by the ROW Lease for the Northstar Oil Pipeline, ADL 415700, except for those lands expressly identified as the Northstar Pipeline ROW (ADL 415700) in the Record of Survey, EPF 20020017, containing 419.13 acres, more or less, recorded as Document Number 2004-001001-0, Barrow Recording District, State of Alaska and released/conveyed to the State those lands encumbered by the ROW Lease for the Northstar Gas Pipeline, ADL 415975, except for those lands expressly identified as the Northstar Pipeline ROW (ADL 415975) in the Record of Survey, EPF 20020017, containing 405.51 acres, more or less recorded as Document Number 2004-001001-0, Barrow Recording District, State of Alaska.
ADL 63574	10/9/2008	TAPS ROW	An Off ROW Access letter was issued under Stipulation 2.9.1 to APSC to take low impact vehicles such as, but not limited to, snow machines, four-wheelers, tuckers, nodwells, and bombardiers off the TAPS ROW during the 2008/2009 winter.
ADL 63574	10/2/2008	TAPS ROW	An amendment to a March 31, 2004 Agreement was entered into, effective January 1, 2007, that deleted Section 3.4 of the original agreement pertaining to insurance coverage and amended Section 3.1 to require annual submittal, by July 1, of an officer's certification that Flint Hills Resources' net equity is in excess of $1.9 Billion.
LAS 27062	10/15/2008	Sec. 31 and 32, T. 11 N, R.8 W, FM AK.	A LUP containing approximately 1.50 acres was issued to conduct winder trail maintenance on a twelve-foot-wide, one-mile-long, historic, winter trail using a small, tracked rotary brusher. The work involved removing deadfall and new-growth brush. The deadfall occurred following the 2000/2001 wildfire in the area. The site was located near PLMP 370.7 and Hot Cat Hill.
ADL 409027	11/28/2008	Sec. 11, 14, 15,16, and 21, T. 11 N, R. 9 E, UM, AK and Sec. 9, T. 11 N, R. 10 E, UM, AK	A SPCO Authorization under Stipulation 1.7 for Kuparuk Pipeline Extension Pipeline Replacement Project was issued to Kuparuk Transportation Company to replace the existing 12inch diameter pipeline with an 18-inch diameter pipeline between CPF-2 and Drill Site 2Z and to construct pig launcher and receiver facilities on state lands adjacent to the existing Kuparuk Pipeline Extension Right-of-Way Lease. The pipeline replacement project will be conducted within the existing Kuparuk Pipeline Extension ROW for approximately 4.15 miles. The pig launcher area is proposed at CPF-2 and will extend west approximately 19 feet beyond the existing Kuparuk Pipeline Extension ROW, encompassing 0.016 acres, more or less. The pig receiver area is proposed at CPF-1 and will extend north approximately 41 feet beyond the existing Kuparuk Pipeline Extension ROW, encompassing 0.0275 acres, more or less.
ADL 228162, Release of Interests	12/10/2008	Records of Survey, EPF 20040045, EPF 20050041, and EPF 2007-04	Lessee Kenai Kachemak Pipeline, LLC released/conveyed to the State those lands encumbered by the Right-of-Way Lease for the Kenai Kachemak Pipeline, ADL 228162, except for those lands expressly identified as the Kenai Kachemak Pipeline Right-of-Way (ADL 228162) in the Kenai-Kachemak Pipeline Project Record of Survey, EPF 20040045, containing 77.86 acres, more or less, recorded as Document 2007-001292-0 in the Homer Recording District, and also recorded as Document 2007-004592-0 in the Kenai Recording District, in the Happy Valley Extension to the Kenai-Kachemak Pipeline Record of Survey, EPF 20050041, containing 16.622 acres, more or less, recorded as Document 2007-001293-0 in the Homer Recording District; and also in the Kenai-Kachemak Pipeline Kasilof Extension Record of Survey, EPF 2007-04, containing 10.074 acres, more or less, recorded as Document 2007-010187-0 in the Kenai Recording District.

*Section = Sec.	Township = T.	South = S	North = N	Range = R.	East = E	West = W	Copper River = CR	Fairbanks = F	Umiat = U	Meridian = M

Third Quarter FY08: January 1, 2009 - March 31, 2009

Permit / ADL Number	Date	Location	Description
LAS 26920	1/6/2009	Sec. 30, T.14 S, R. 10 E, FM, AK	A LUP containing 5.0 acres was issued to APSC for storage of mineral and non-hazardous materials and equipment at OMS 41-3, Donnelly Pit.
ADL 409027, Lease Amendment	1/12/2009	Sec. 11, 14, 15,16, and 21, T. 11 N, R. 9 E, UM, AK and Sec. 9, T. 11 N, R. 10 E, UM, AK	An amendment to replace the existing Kuparuk Pipeline Extension 12” diameter pipe with 18” diameter pipe for approximately 4.15 miles, to add land to the ROW to construct a pig launcher at CPF-2 extending west approximately 19 feet beyond the existing Kuparuk Pipeline Extension ROW, and to add land to the ROW construct a pig receiver at CPF-1 that will extend north approximately 41 feet beyond the existing Kuparuk Pipeline Extension ROW. The total acreage proposed for the pig launcher and receiver encompasses 0.0435 acres, more or less.
LAS 27093	2/27//2009	Sec.26 and 35, T. 1 N, R. 14 E, UM, AK and Sec. 22, T. 1 S, R. 14 E, UM, AK and Sec. 33, T. 2 S, R. 14 E, UM, AK and Sec. 4, 29, 31, and 32, T. 3 S, R. 14 E, UM, AK and Sec. 5 and 8, T. 4 S, R. 14 E, UM, AK	A LUP was issued to APSC for four pipeline river crossing locations from the Dalton Highway to the east bank of the Sagavanirktok River and three different alternate routes from Happy Valley Airstrip across the Sagavanirktok River to the ease bank for periodic crossing during winter with construction equipment to support TAPS.
ADL 415472 and ADL 415965	3/4/2009	Sec. 13, T. 10 N, R. 16 E, UM, AK	An authorization under Lease Stipulation 14 was issued to BPTA for Phase 2 construction of the Badami Weir as described in the November 2008 Badami Weir Maintenance Engineering, Issued for Construction report.
ADL 418605	3/6/2009	Sec. 23, T. 6 N, R. 4 W, FM, AK	A material sale contract for 10,000 cubic yards of highly fractured, deeply weathered bedrock was issued to APSC for 8.5 acres. The area is also identified as OMS 67-1

*Section = Sec.	Township = T.	South = S	North = N	Range = R.	East = E	West = W	Copper River = CR	Fairbanks = F	Umiat = U	Meridian = M

Fourth Quarter FY08: April 1, 2009 - June 30, 2009

Permit / ADL Number	Date	Location	Description
LAS 27125	4/10/2009	Sec. 29, T. 9 S, R. 5 W, CRM, AK	A LUP containing approximately 0.23 acres, located near TAPS PLMP 792.5, was issued to APSC for the purpose of excavating around the buried TAPS pipeline to investigate the integrity of the pipe, repair the pipe if needed, and re-coat the pipe as part of APSC Project F909 – 2009 Mainline Integrity Investigations.
TWUP P2007-7, Amendment No. 2	4/14/2009	Sec. 8 T.12 S, R. 12 E, UM, AK	An amendment to TWUP P2007-7 was issued to APSC to remove the use of water to provide domestic water for the temporary housing at the Old Atigun Camp pad location at Dalton Highway Milepost 243. The PLMP was also corrected from PLMP 114 to PLMP144.
TWUP P2009-3	5/14/2009	Sec. 15, T. 28 N, R. 12 W, FM, AK	A TWUP was issued to APSC for withdrawal of up to 30,000 gallons per day (gpd) from Slate Creek near PLMP 237.6 for the purpose of dust control, soil compaction, sand-cement slurry and water filled traffic barriers to support the Shorted Pipeline Road Casing Removal Project at PLMP 246.2.
TWUP P2009-2	5/14/2009	Sec. 31, T. 6 N, R. 14 E, UM, AK and Sec. 20, T. 5 N, R. 14 E, UM, AK and Sec. 16, T. 4 N, R. 14 E, UM, AK	A TWUP was issued to APSC for withdrawal of up to 30,000 gallons per day (gpd) from the vaults at Check Valves 8, 9, and 10 for the purpose of maintenance related right-of-way access, ice road construction, and pad maintenance from PLMP 35 through PLMP 62.
TWUP P2009-5	5/14/2009	Sec. 26, T. 27 N, R. 13 W, FM, AK	A TWUP was issued to APSC for withdrawal of up to 30,000 gallons per day (gpd) from No-Name Pond at DHMP 165.1 for the purpose of dust control, soil compaction, sand-cement slurry, and water-filled traffic barriers to support the Shorted Pipeline Road Casing Removal Project at PLMP 246.2.
TWUP P2009-4	5/14/2009	Sec. 6, T. 27 N, R. 12 W, FM, AK	A TWUP was issued to APSC for withdrawal of up to 30,000 gallons per day (gpd) from Rosie Creek at DHMP 170 for the purpose of dust control, soil compaction, sand-cement slurry, and water-filled traffic barriers to support the Shorted Pipeline Road Casing Removal Project at PLMP 246.2.
LAS 27228	6/17/2009	Sec. 9, T. 8 S, R. 2 W, CRM, AK	A LUP containing approximately 0.76 acres was issued to APSC for the purpose of repairing a construction-era guidebank and bridge abutment rip-rap aprons near TAPS Access Road 7 APL-2 at Richardson Highway MP 33.2 which were damaged in the 2006 and 2007 flooding.
LAS 27192	6/24/2009	Sec. 2 and 3, T. 20 S, R. 11 E, FM, AK	A LUP containing approximately 5 acres was issued to APSC for the purpose of storage of mineral material and non-toxic, non-hazardous TAPS materials and equipment, located within the working limits of OMS 35-1.2.
LAS 27193	6/24/2009	Sec. 34, T. 7 S, R. 8 E, FM, AK	A LUP containing approximately 5 acres was issued to APSC for the purpose of storage of mineral material and non-toxic, non-hazardous TAPS materials and equipment, located within the working limits of OMS 49-3.
LAS 27194	6/24/2009	Sec. 25 and 26, T. 11 N, R. 9 W, FM, AK	A LUP containing approximately 5 acres was issued to APSC for the purpose of storage of mineral material and non-toxic, non-hazardous TAPS materials and equipment, located within the working limits of OMS 75-1R.
LAS 27195	6/24/2009	Sec. 30, T. 8 N, R. 5 W, FM, AK	A LUP containing approximately 5 acres was issued to APSC for the purpose of storage of mineral material and non-toxic, non-hazardous TAPS materials and equipment, located within the working limits of OMS 70-0.0.
LAS 27196	6/24/2009	Sec. 24, T. 3 N, R. 2 W, FM, AK	A LUP containing approximately 5 acres was issued to APSC for the purpose of storage of mineral material and non-toxic, non-hazardous TAPS materials and equipment, located within the working limits of OMS 63-4.
ADL 63574, Lease Amendment	6/29/2009	TAPS	An amendment to the Right-of-Way lease for the TAPS was executed to amend language in Stipulation 3.2.1.1 to clarify the use of the Underwriter Laboratories (UL) 142 tanks along TAPS.
ADL 228162, Guaranty	6/29/2009	KKPL	A letter was sent accepting the unconditional guaranty of Chevron Corporation for Kenai Kachemak Pipeline Right-of-Way Lease and determining that it satisfies KKPL's obligation to furnish other security or undertaking to protect the public from damage for which KKPL may be liable.

Appendix E – Physical Characteristics of SPCO Jurisdictional Pipelines

Pipeline System	Diameter (inches)	Normal Wall Thickness (inches)	Product	Year Constructed	System Length (miles)
Alpine Diesel Pipeline	2.375	0.156	Diesel & Misc. Fluids	1998-1999	34.2 (23.7 on state land)
Alpine Oil Pipeline	14	0.312 to 0.438	Sales Oil	1998-1999	34.2 (23.7 on state land)
Alpine Utility Pipeline	12.75	0.330	Treated Seawater	1998-1999	34.2 (23.7 on state land)
Badami Sales Oil Pipeline	12	0.281 aboveground 0.500 belowground	Sales Oil	1998	25 (all on state land)
Badami Utility Pipeline	6	0.375 aboveground 0.432 river crossing	Natural Gas and Product	1998	31 (all on state land)
Endicott Pipeline	16	0.312	Sales Oil	1987	26 (all on state land)
Kasilof Extension to KKPL	6.63	0.280 and 0.432	Natural Gas	2006	4.2 (all on state land)
KKPL Mainline and HVE	12.75	0.330 and 0.500	Natural Gas	2003-2004	50 including the HVE (42 on state land)
Kuparuk Pipeline	24	0.406 (0.750 in Kuparuk Floodplain)	Sales Oil	1984	28 (all on state land)
Kuparuk Pipeline Extension	18	0.375 (original construction); 0.438 (2009 replaced section)	Sales Oil	1981 original; 2009 partial replacement	9 (all on state land)
Milne Point (Oil) Pipeline	14	0.312	Sales Oil	1984	10 (all on state land)
Milne Point Product Pipeline	8	0.277	Natural Gas Liquids	2000	10 (all on state land)
Nikiski Alaska Pipeline	10.75	0.188 to 0.625	Jet Fuel, Gasoline, Diesel	1976	52.8 (20 miles on state land)
Northstar Gas Pipeline	10.15	0.307- (0.594 sub-sea)	Natural Gas	2000-2001	16 (all on state land)
Northstar Oil Pipeline	10.75	0.307 (0.594 sub-sea)	Sales Oil	2000-2001	17 (all on state land)
Nuiqsut Natural Gas Pipeline	3.5	0.203	Natural Gas	1998-1999	14.4 (2.4 miles on state land)
Oliktok Pipeline	16	0.342- (0.750 in Kuparuk Floodplain)	Natural Gas Liquids	1981	28 (all on state land)
TAPS	48	0.462 to 0.562	Sales Oil	1975-1977	800

Appendix F – Lease Required Contact Information

Pipeline	Lease	Registered Agent	Lease	Authorized Representative	Lease	Field Representative
Alpine Pipelines	Sec. 30	Mr. Bill Sargent Engineering & Operations Manager Alpine Transportation Company P.O. Box 100360 ATO 908 Anchorage, AK 99510-0360	Sec. 30	Mr. Bill Sargent Engineering & Operations Manager Alpine Transportation Company P.O. Box 100360 ATO 908 Anchorage, AK 99510-0360	Sec. 30	David Todd / Larry Baker CPF-3 Operations Superintendent ConocoPhillips Alaska, Inc. P.O. Box 196105, NSK 22 Anchorage, AK 99519-6105
Badami Pipelines	Sec. 8(j)	CT Corporation, Re: BPTA Suite 202 9360 Glacier Highway Juneau, AK 99801	Sec. 26	Mr. Don Turner Vice President, BPTA, Inc. P.O. Box 190848 Anchorage, AK 99519-0848	Sec. 26	Bruce W. Robinson / Thomas J. Barnes Mail Stop END 900 E. Benson Blvd. Anchorage, AK 99508
Endicott	Sec. 4(j)	CT Corporation, Re: BPTA Suite 202 9360 Glacier Highway Juneau, AK 99801	Stip. 1.3.2	Mr. Don Turner Vice President, BPTA, Inc. P.O. Box 190848 Anchorage, AK 99519-0848	Stip. 1.3.2	Bruce W. Robinson / Thomas J. Barnes Mail Stop END 900 E. Benson Blvd. Anchorage, AK 99508
KKPL	Sec. 8(j)	Ms. Jaci Stasak Marathon Pipe Line, LLC P.O. Box 2399 Kenai, AK 99611	Sec. 30	Mr. Daniel Riemer, President Kenai Kachemak Pipeline, LLC 5555 San Felipe Road Houston, TX 77056	Sec. 30	Marathon Pipe Line, LLC Attn: Mr. Raymond Price Kenai Area Manager P.O Box 2399 Kenai, AK 99611
Kuparuk and Kuparuk Extension	Sec. 4(j)	Mr. Bill Sargent Engineering & Operations Manager Alpine Transportation Company P.O. Box 100360 ATO 908 Anchorage, AK 99510-0360	Stip. 1.3.2	Mr. Bill Sargent Engineering & Operations Manager Alpine Transportation Company P.O. Box 100360 ATO 908 Anchorage, AK 99510-0360	Stip. 1.3.2	David Todd / Larry Baker CPF-3 Operations Superintendent ConocoPhillips Alaska, Inc. P.O. Box 196105, NSK 22 Anchorage, AK 99519-6105
Milne Point Oil	Sec. 4(j)	CT Corporation, Re: BPTA Suite 202 9360 Glacier Highway Juneau, AK 99801	Stip. 1.3.2	Mr. Don Turner Vice President, BPTA, Inc. P.O. Box 190848 Anchorage, AK 99519-0848	Stip. 1.3.2	Dale O. Kruger / Jeff R. Michels Mail Stop MPU 900 E. Benson Blvd. Anchorage, AK 99508

Appendix F - Lease Required Contact Information *(continued)*

Pipeline	Lease	Registered Agent	Lease	Authorized Representative	Lease	Field Representative
Milne Point Product (NGL)	Sec. 8(j)	CT Corporation Re: BPTA Suite 202 9360 Glacier Highway Juneau, AK 99801	Sec. 30	Mr. Don Turner Vice President, BPTA, Inc. P.O. Box 190848 Anchorage, AK 99519-0848	Sec. 30	Dale O. Kruger / Jeff R. Michels Mail Stop MPU 900 E. Benson Blvd. Anchorage, AK 99508
Nikiski Alaska	Sec. 11	Tesoro Alaska Pipeline Co. Attn: Shawn Brown Manager Pipeline & Terminals P.O. Box 3369 Kenai, AK 99611	Stip. 1.4.2			Tesoro Alaska Pipeline Co, Attn: Shawn Brown Manager Pipelines & Terminals P.O. Box 3369 Kenai, AK 99611
Northstar Pipelines	Sec. 8(j)	CT Corporation Re: BPTA Suite 202 9360 Glacier Highway Juneau, AK 99801	Sec. 30	Mr. Don Turner Vice President, BPTA, Inc. P.O. Box 190848 Anchorage, AK 99519-0848	Sec. 30	Wayne Kuykendall / Gary Herring Mail Stop Northstar 900 E. Benson Blvd. Anchorage, AK 99508
Nuiqsut Natural Gas Pipeline	Sec. 8(j)	Mr. Marvin Olson Director, Department of Public Works North Slope Borough PO Box 350 Barrow, AK 99723	Sec. 30	Mayor Edward Itta North Slope Borough PO Box 69 Barrow, Alaska 99732	Sec. 30	Mr. Marvin Olson Director, Dept. of Public Works North Slope Borough PO Box 350 Barrow, Alaska 99723
Oliktok Pipeline	Sec. 4(j)	Mr. Bill Sargent Engineering & Operations Manager Alpine Transportation Company P.O. Box 100360 ATO 908 Anchorage, AK 99510-0360	Stip. 1.3.2	Mr. Bill Sargent Engineering & Operations Manager Alpine Transportation Company P.O. Box 100360 ATO 908 Anchorage, AK 99510-0360	Stip. 1.3.2	David Todd / Larry Baker CPF-3 Operations Superintendent ConocoPhillips Alaska, Inc. P.O. Box 196105, NSK 22 Anchorage, AK 99519-6105
TAPS	Sec. 12	Alyeska Pipeline Service Company Attn: Mr. Kevin Hostler, President P.O. Box 196660 Anchorage, AK 99519-6660	Stip. 1.5.3	Mr. Joseph Robertson JPO/DOT Liaison Director, APSC P.O. Box 196660, MS 502 Anchorage, AK 99519-6660	N/A	N/A

Appendix G – Acreage, Survey, and Lease Information

ADL #	Lease Name	Lease Effective Date	Lease Expiration Date	Lessee	State Acreage	Survey #
415932	Alpine Diesel Pipeline	12/15/1998	12/14/2018	ConocoPhillips Company	148.51 acres	EPF 2002-40*
415701	Alpine Oil Pipeline	12/15/1998	12/14/2018	ConocoPhillips Company	148.66 acres	EPF 2002-40
415857 **	Alpine Utility Pipeline	1/6/1999	1/5/2019	ConocoPhillips Company	148.65 acres	EPF 2002-40
415472	Badami Sales Oil Pipeline	12/15/1997	12/14/2022	BP Transportation (Alaska) Inc.	1,240 acres***	EPF 2002-18; not complete
415965	Badami Utility Pipeline	12/15/1997	12/14/2022	BP Transportation (Alaska, Inc.	352.1 acres***	EPF 2002-18; not complete
410562	Endicott Pipeline	8/5/1986	5/2/2034	Endicott Pipeline Company	1,072.636 acres	ASLS 84-96
228162	Kenai Kachemak Pipeline	11/26/2002	11/25/2032	Kenai Kachemak Pipeline, LLC	104.556 acres	KKPL - EPF 2004-45 HVE - EPF 2005-41 KE - EPF 2007-04
402294	Kuparuk Pipeline	8/26/1980	5/2/2034	Kuparuk Transportation Company	485.58 acres	ASLS 87-15
409027	Kuparuk Pipeline Extension	4/18/1983	5/2/2034	Kuparuk Transportation Company	159.09 acres	ASLS 87-15
410221	Milne Point (Oil) Pipeline	1/15/1985	5/2/2034	Milne Point Pipeline, LLC+	186.92 acres	ASLS 84-114
416172	Milne Point Products Pipeline	12/5/2000	12/4/2030	Milne Point Pipeline, LLC+	258.6 acres***	Not surveyed
69354	Nikiski Alaska Pipeline	1/30/1976	1/29/2031	Tesoro Alaska Pipeline Company	64 acres	ASLS 76-215
415975	Northstar Gas Pipeline	10/1/1999	9/30/2019	BP Transportation (Alaska), Inc.	405.51 acres	EPF 2002-17
415700	Northstar Oil Pipeline	10/1/1999	9/30/2019	BP Transportation (Alaska), Inc.	419.13 acres	EPF 2002-17
416202	Nuiqsut Natural Gas Pipeline	3/15/1999	3/14/2019	North Slope Borough	17.67 acres	As-built survey approved by DNR 12/17/2003
411731	Oliktok Pipeline	6/1/1986	5/2/2034	Oliktok Pipeline Company	485.58 acres	ASLS 87-15
63574	Trans-Alaska Pipeline System	5/3/1974	5/2/2034	TAPS Owners++	6,021.87 acres+++	Multiple surveys++++

**A typographical error exists on the survey plat with respect to the acreage of Parcel 4, but the square feet of Parcel 4 is correct; total acreage is 148.51 acres*
*** ADL 415857 is a ROW Grant, not a lease.*
****Acreage based on construction ROW acreage from lease, not surveyed acreage*
+ Wholly owned by BPTA
++ BP Pipelines Alaska Inc. (46.93%), ConocoPhillips Alaska Transportation Inc. (28.29%), Exxon/Mobil Pipeline Co. (20.34%), Unocal Pipeline Company (1.36%), Koch Alaska Pipeline Co. LLC (3.08%)
+++ Per Appraisal 3165, DNR Summary of Appraisal dated 7/21/2006, and Memorandum of May 17, 2007 from the Review Appraiser to the SPCO to add fuel gas line acreage.
++++ Includes the TAPS centerline survey, surveys of pump stations on State land, and as-built surveys for ROW amendments.

Appendix H – Pipeline Right-of-Way Lease Appraisal Information

Pipeline	ADL #	ROW Status	State Acres	Rental	Next Appraisal Due (Prior to)
Alpine Oil	415701	Operations	148.66	$77,713*	12/15/2013
Alpine Diesel	415932	Operations	148.51	$77,626*	12/15/2013
Alpine Utility	415857	Operations	148.65	$77,703*	1/6/2014
Badami Oil	415472	Construction	1,240.00	$540,144	12/15/2012
Badami Utility	415965	Construction	352.1	$181,122	12/15/2012
Endicott	410562	Operations	1,072.64	$735,627	8/5/2013
Kenai Kachemak	228162	Operations	104.556	$29,709	11/26/2012
Kuparuk	402294	Operations	485.58	$370,347*	8/26/2013
Kuparuk Extension	409027	Operations	159.08	$138,599*	4/18/2013
Milne Point (Oil)	410221	Operations	186.92	$162,845	1/15/2013
Milne Point Products	416172	Construction	258.6	$225,292	12/5/2010
Oliktok	411731	Operations	485.58	$370,347*	1/20/2013
Nikiski Alaska	69354	Operations	64.02	$15,207	1/3/2009
Northstar Oil	415700	Operations	419.13	$124,630+	10/1/2009
Northstar Gas	415975	Operations	405.51	$115,473+	10/1/2009
Nuiqsut Natural Gas	416202	Operations	17.67	**	3/15/2014
TAPS	63574	Operations	6,021.87	$220,956	***

** Current Appraisal under appeal*

*** Current Appraisal was due 3/15/2009, but not timely received by DNR*

**** Last Appraisal (No. 3165) was completed in 2002 and is under appeal. SPCO and DNR Appraisal Section agreed a retrospective appraisal is acceptable upon appeal resolution*

+ Annual rental adjusted to operations ROW acreage during FY09 after Releases of Interests were executed

Appendix I – SPCO Surveillance Reports Issued in Fiscal Year 2009

Pipeline	Trip or Review Date	Topic	Section Stipulation (Sec/Stip)	Number	Sec/Stip Title	Observation	SPCO Section
TAPS	2/15/2008	Integrity Dig	Stip	1.2.4	Responsibilities	Satisfactory	Compliance
TAPS	2/15/2008	Integrity Dig	Stip	1.18	Surveillance and Maintenance	Satisfactory	Compliance
TAPS	2/15/2008	Integrity Dig	Stip	2.2.6.2	Sanitation and Waste Disposal	Satisfactory	Compliance
TAPS	2/15/2008	Integrity Dig	Stip	2.9.1	Off Right-of-Way Traffic	Satisfactory	Compliance
TAPS	2/15/2008	Integrity Dig	Stip	1.18	Surveillance and Maintenance	Satisfactory	Compliance
TAPS	2/19/2008	Integrity Dig	Sec	6	Books, Accounts and Reports Access to Property and Records	Satisfactory	Compliance
TAPS	2/19/2008	Integrity Dig	Sec	10	Damage or Destruction of Leasehold or other Property	Satisfactory	Compliance
TAPS	2/19/2008	Integrity Dig	Sec	22	Duty of Lessees to Prevent or Abate	Satisfactory	Compliance
TAPS	2/19/2008	Integrity Dig	Stip	1.2.3	Responsibilities	Satisfactory	Compliance
TAPS	2/19/2008	Integrity Dig	Stip	1.18	Surveillance and Maintenance	Satisfactory	Compliance
TAPS	2/19/2008	Integrity Dig	Stip	1.20	Health and Safety	Satisfactory	Compliance
TAPS	2/19/2008	Integrity Dig	Stip	1.21	Conduct of Operations	Satisfactory	Compliance
TAPS	2/19/2008	Integrity Dig	Stip	2.2.2.2	Water and Land Pollution	Satisfactory	Compliance
TAPS	2/19/2008	Integrity Dig	Stip	2.4.1.1	Erosion Control	Satisfactory	Compliance
TAPS	4/9/2008	Integrity Dig	Stip	1.18	Surveillance and Maintenance	Satisfactory	Compliance
TAPS	4/9/2008	Integrity Dig	Stip	2.2.2.2	Water and Land Pollution	Satisfactory	Compliance
TAPS	4/9/2008	Integrity Dig	Stip	2.9.1	Off Right-of-Way Traffic	Satisfactory	Compliance
TAPS	4/9/2008	Integrity Dig	Stip	4.1.1	State Laws, Regulations, Permits and Authorizations	Satisfactory	Compliance
Badami Oil	6/16/2008	Badami Weir	Stip	1.11.2	Regulation of Access	Satisfactory	Compliance
Badami Utility	6/16/2008	Badami Weir	Stip	1.11.2	Regulation of Access	Satisfactory	Compliance
Badami Oil	6/16/2008	Badami Weir	Stip	2.3	Erosion and Sedimentation Control	Satisfactory	Compliance
Badami Utility	6/16/2008	Badami Weir	Stip	2.3	Erosion and Sedimentation Control	Satisfactory	Compliance
Badami Oil	6/16/2008	Badami Weir	Stip	2.6.1	Big Game Movements	Satisfactory	Compliance
Badami Utility	6/16/2008	Badami Weir	Stip	2.6.1	Big Game Movements	Satisfactory	Compliance
Badami Oil	6/16/2008	Badami Weir	Stip	2.7.1	Disturbance or Use of Natural Waters	Satisfactory	Compliance
Badami Utility	6/16/2008	Badami Weir	Stip	2.7.1	Disturbance or Use of Natural Waters	Satisfactory	Compliance

Appendix I – SPCO Surveillance Reports Issued in FY09, Continued

Pipeline	Trip or Review Date	Topic	Sec/ Strip	Number	Sec/Stip Title	Observation	SPCO Section
TAPS	6/24/2008	LWC Inspection	Stip	2.4, 2.5.1.1, 2.12.1	Crossing of Streams, River or Flood	Satisfactory	ADF&G
TAPS	6/24/2008	Culvert Inspection	Stip	2.4, 2.5.1.1, 2.12.1	Plains,	Satisfactory	ADF&G
TAPS	6/24/2008	Culvert Inspection	Stip	2.4, 2.5.1.1, 2.12.1	Seeding and Planting,	Satisfactory	ADF&G
TAPS	6/24/2008	LWC Inspection	Stip	2.4, 2.5.1.1, 2.12.1	Passage of Fish, and	Satisfactory	ADF&G
TAPS	6/24/2008	Guidebank construction and Stream Diversion Inspection	Stip	2.4, 2.5.1.1, 2.12.1	Restoration	Satisfactory	ADF&G
TAPS	6/24/2008	LWC Inspection	Stip	2.4, 2.5.1.1, 2.12.1		Corrected on the Spot (COTS)	ADF&G
TAPS	6/24/2008	LWC Inspection	Stip	2.4, 2.5.1.1, 2.12.1		COTS	ADF&G
TAPS	6/24/2008	LWC Inspection	Stip	2.4, 2.5.1.1, 2.12.1		COTS	ADF&G
TAPS	6/24/2008	LWC Inspection	Stip	2.4, 2.5.1.1, 2.12.1		COTS	ADF&G
TAPS	6/24/2008	LWC Inspection	Stip	2.4, 2.5.1.1, 2.12.1		COTS	ADF&G
TAPS	6/24/2008	Culvert Inspection	Stip	2.4, 2.5.1.1, 2.12.1		Satisfactory	ADF&G
TAPS	6/24/2008	Bridge Inspection	Stip	2.4, 2.5.1.1, 2.12.1		Satisfactory	ADF&G
TAPS	6/24/2008	Culvert Inspection	Stip	2.4, 2.5.1.1, 2.12.1		Satisfactory	ADF&G
KKPL	6/26/2008	ROW Tour	Sec	1(b)(c)	Lease of ROW	Satisfactory	Compliance
KKPL	6/26/2008	ROW Tour	Sec	6(a)(b)	Reservation of Certain Rights	Satisfactory	Compliance
KKPL	6/26/2008	ROW Tour	Sec	8(c)(d)(h)	Covenants	Satisfactory	Compliance
KKPL	6/26/2008	ROW Tour	Sec	15(a)(b)	Conduct of Operations	Satisfactory	Compliance
KKPL	6/26/2008	ROW Tour	Sec	16(a)	Environmental Compliance	Satisfactory	Compliance
KKPL	6/26/2008	ROW Tour	Sec	20	Information	Satisfactory	Compliance
KKPL	6/26/2008	ROW Tour	Stip	1.2.1	Communications	Satisfactory	Compliance
KKPL	6/26/2008	ROW Tour	Stip	1.5	Conduct of Operations	Satisfactory	Compliance
KKPL	6/26/2008	ROW Tour	Stip	1.11.1, 1.11.2	Regulation of Access	Satisfactory	Compliance
KKPL	6/26/2008	ROW Tour	Stip	1.12.1, 1.12.2	Storage	Satisfactory	Compliance
KKPL	6/26/2008	ROW Tour	Stip	2.2.1	Erosion and Sedimentation Control	Satisfactory	Compliance
KKPL	6/26/2008	ROW Tour	Stip	2.7.1, 2.7.2	Stabilize, Revegetate and Restore Disturbed Areas	Satisfactory	Compliance

Appendix I – SPCO Surveillance Reports Issued in FY09, continued

Pipeline	Trip or Review Date	Topic	Sec/ Stip	Number	Sec/Stip Title	Observation	SPCO Section
TAPS	7/8/2008	LWC Inspection	Stip	2.4, 2.5.1.1, 2.12.1	Crossing of Streams, River or Flood Plains, Seeding and Planting, Passage of Fish, and Restoration	Satisfactory	ADF&G
TAPS	7/8/2008	LWC Inspection	Stip	2.4, 2.5.1.1, 2.12.1		Satisfactory	ADF&G
TAPS	7/8/2008	LWC Inspection	Stip	2.4, 2.5.1.1, 2.12.1		Satisfactory	ADF&G
TAPS	7/8/2008	LWC Inspection	Stip	2.4, 2.5.1.1, 2.12.1		Satisfactory	ADF&G
TAPS	7/8/2008	LWC Inspection	Stip	2.4, 2.5.1.1, 2.12.1		Satisfactory	ADF&G
TAPS	7/8/2008	Culvert Inspection	Stip	2.4, 2.5.1.1, 2.12.1		Satisfactory	ADF&G
TAPS	7/8/2008	Ice (Access) Ramp Inspection	Stip	2.4, 2.5.1.1, 2.12.1		Satisfactory	ADF&G
TAPS	7/8/2008	Culvert Inspection	Stip	2.4, 2.5.1.1, 2.12.1		COTS	ADF&G
TAPS	7/8/2008	LWC Inspection	Stip	2.4, 2.5.1.1, 2.12.1		Satisfactory	ADF&G
TAPS	7/8/2008	LWC Inspection	Stip	2.4, 2.5.1.1, 2.12.1		Satisfactory	ADF&G
TAPS	7/8/2008	LWC Inspection	Stip	2.4, 2.5.1.1, 2.12.1		Satisfactory	ADF&G
TAPS	7/8/2008	Revetment Inspection	Stip	2.4, 2.5.1.1, 2.12.1		Satisfactory	ADF&G
TAPS	7/28/2008	OMS Inventory	Stip	2.6	Material Sites	Satisfactory	ROW
TAPS	7/28/2008	OMS Inventory	Stip	2.6	Material Sites	Satisfactory	ROW
TAPS	7/28/2008	OMS Inventory	Stip	2.6	Material Sites	Satisfactory	ROW
TAPS	7/28/2008	OMS Inventory	Stip	2.6	Material Sites	Satisfactory	ROW
TAPS	7/28/2008	OMS Inventory	Stip	2.6	Material Sites	Satisfactory	ROW
TAPS	7/28/2008	OMS Inventory	Stip	2.6	Material Sites	Satisfactory	ROW
TAPS	7/28/2008	OMS Inventory	Stip	2.6	Material Sites	Satisfactory	ROW
TAPS	7/28/2008	OMS Inventory	Stip	2.6	Material Sites	Satisfactory	ROW
TAPS	7/28/2008	OMS Inventory	Stip	2.6	Material Sites	Satisfactory	ROW
TAPS	7/28/2008	OMS Inventory	Stip	2.6	Material Sites	Satisfactory	ROW
TAPS	7/28/2008	OMS Inventory	Stip	2.6	Material Sites	Satisfactory	ROW
TAPS	7/28/2008	OMS Inventory	Stip	2.6	Material Sites	Satisfactory	ROW
TAPS	7/28/2008	OMS Inventory	Stip	2.6	Material Sites	Satisfactory	ROW
TAPS	7/28/2008	OMS Inventory	Stip	2.6	Material Sites	Satisfactory	ROW
TAPS	7/28/2008	OMS Inventory	Stip	2.6	Material Sites	Satisfactory	ROW
TAPS	7/28/2008	OMS Inventory	Stip	2.6	Material Sites	Satisfactory	ROW

Appendix I – SPCO Surveillance Reports Issued in FY09, continued

Pipeline	Trip or Review Date	Topic	Sec/ Stip	Number	Sec/Stip Title	Observation	SPCO Section
TAPS	7/28/2008	OMS Inventory	Stip	2.6	Material Sites	Satisfactory	ROW
TAPS	7/28/2008	OMS Inventory	Stip	2.6	Material Sites	Satisfactory	ROW
TAPS	7/28/2008	OMS Inventory	Stip	2.6	Material Sites	Satisfactory	ROW
TAPS	7/28/2008	OMS Inventory	Stip	2.6	Material Sites	Satisfactory	ROW
TAPS	7/28/2008	OMS Inventory	Stip	2.6	Material Sites	Satisfactory	ROW
TAPS	8/15/2008	August Shutdown	Sec	6(a)	Book, Accounts, Records	Satisfactory	Compliance
TAPS	8/15/2008	August Shutdown	Sec	10(a)	Damage/Destruction of Leasehold or Other Property	Satisfactory	Compliance
TAPS	8/15/2008	August Shutdown	Sec	17(a)	Reservation of Certain Rights to the State	Satisfactory	Compliance
TAPS	8/15/2008	August Shutdown	Sec	22(a), (b)	Duty of Lessee to Prevent or Abate	Satisfactory	Compliance
TAPS	8/15/2008	August Shutdown	Stip	1.18.2	Surveillance and Maintenance	Satisfactory	Compliance
TAPS	8/15/2008	August Shutdown	Stip	1.19.1	Housing and Quarters	Satisfactory	Compliance
TAPS	8/15/2008	August Shutdown	Stip	1.20.1	Health and Safety	Satisfactory	Compliance
TAPS	8/15/2008	August Shutdown	Stip	2.2.6.2	Sanitation and Waste Disposal	Satisfactory	Compliance
TAPS	8/15/2008	August Shutdown	Stip	2.9.1	Off ROW Traffic	Satisfactory	Compliance
TAPS	8/15/2008	August Shutdown	Stip	3.2.2.3	Special Standards	Satisfactory	Compliance
TAPS	8/18/2008	Boat Launch inspection	Stip	2.4, 2.5.1.1, 2.12.1	Crossing of Streams, River or Flood Plains, Seeding and Planting, Passage of Fish, and Restoration	Satisfactory	ADF&G
TAPS	8/18/2008	Culvert Inspection	Stip	2.4, 2.5.1.1, 2.12.1		Significant	ADF&G
TAPS	8/18/2008	LWC Inspection	Stip	2.4, 2.5.1.1, 2.12.1		Satisfactory	ADF&G
TAPS	8/18/2008	LWC Inspection	Stip	2.4, 2.5.1.1, 2.12.1		Satisfactory	ADF&G
TAPS	8/18/2008	LWC Inspection	Stip	2.4, 2.5.1.1, 2.12.1		Satisfactory	ADF&G
TAPS	8/18/2008	LWC Inspection	Stip	2.4, 2.5.1.1, 2.12.1		Satisfactory	ADF&G
TAPS	8/18/2008	LWC Inspection	Stip	2.4, 2.5.1.1, 2.12.1		Satisfactory	ADF&G
TAPS	8/18/2008	LWC Inspection	Stip	2.4, 2.5.1.1, 2.12.1		Satisfactory	ADF&G
TAPS	8/18/2008	LWC Inspection	Stip	2.4, 2.5.1.1, 2.12.1		Satisfactory	ADF&G
TAPS	8/18/2008	LWC Inspection	Stip	2.4, 2.5.1.1, 2.12.1		Satisfactory	ADF&G
TAPS	8/18/2008	LWC Inspection	Stip	2.4, 2.5.1.1, 2.12.1		Satisfactory	ADF&G
TAPS	8/18/2008	LWC Inspection	Stip	2.4, 2.5.1.1, 2.12.1		Satisfactory	ADF&G
TAPS	8/18/2008	LWC Inspection	Stip	2.4, 2.5.1.1, 2.12.1		COTS	ADF&G
TAPS	8/18/2008	LWC Inspection	Stip	2.4, 2.5.1.1, 2.12.1		Satisfactory	ADF&G
TAPS	8/18/2008	Culvert Inspection	Stip	2.4, 2.5.1.1, 2.12.1		COTS	ADF&G

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Pipeline	Trip or Review Date	Topic	Sec/ Stip	Number	Sec/Stip Title	Observation	SPCO Section
Kuparuk	8/28/2008	Orientation tour CPAI facilities	Stip	1.11.1	Health and Safety	Satisfactory	Compliance
Kuparuk	8/28/2008	Orientation tour CPAI facilities	Stip	1.17.1	Regulation of Access	Satisfactory	Compliance
Kuparuk	8/28/2008	Orientation tour CPAI facilities	Stip	2.4.6.1	Big Game Movements	Satisfactory	Compliance
Kuparuk	8/28/2008	Orientation tour CPAI facilities	Sec	4 (a)(h)	Covenants	Satisfactory	Compliance
Kuparuk	8/28/2008	Orientation tour CPAI facilities	Sec	7a	Reservation of Certain Rights	Satisfactory	Compliance
Oliktok	8/28/2008	Orientation tour CPAI facilities	Stip	1.11.1	Health and Safety	Satisfactory	Compliance
Oliktok	8/28/2008	Orientation tour CPAI facilities	Stip	1.17.1	Regulation of Access	Satisfactory	Compliance
Oliktok	8/28/2008	Orientation tour CPAI facilities	Stip	2.4.6.1	Big Game Movements	Satisfactory	Compliance
Oliktok	8/28/2008	Orientation tour CPAI facilities	Sec	4h	Covenants	Satisfactory	Compliance
Oliktok	8/28/2008	Orientation tour CPAI facilities	Sec	7a	Reservations of Certain Rights to the State	Satisfactory	Compliance
KPE	8/28/2008	Orientation tour CPAI facilities	Stip	1.11.1	Health and Safety	Satisfactory	Compliance
KPE	8/28/2008	Orientation tour CPAI facilities	Stip	1.17.1	Regulation of Access	Satisfactory	Compliance
KPE	8/28/2008	Orientation tour CPAI facilities	Stip	2.4.6.1	Big Game Movements	Satisfactory	Compliance
KPE	8/28/2008	Orientation tour CPAI facilities	Sec	7a	Reservation of Certain Rights	Satisfactory	Compliance
Milne Pt Oil	8/28/2008	Orientation tour BP facilities	Sec	4d	Covenants	Satisfactory	Compliance
Milne Pt Oil	8/28/2008	Orientation tour BP facilities	Sec	7a	Reservations of Certain Rights to the State	Satisfactory	Compliance
Milne Pt Oil	8/28/2008	Orientation tour BP facilities	Stip	1.3.6	Responsibilities	Satisfactory	Compliance
Milne Pt Oil	8/28/2008	Orientation tour BP facilities	Stip	1.11.1	Health & Safety	Satisfactory	Compliance
Milne Pt Oil	8/28/2008	Orientation tour BP facilities	Stip	1.17.1	Regulation of Access	Satisfactory	Compliance
Milne Pt Oil	8/28/2008	Orientation tour BP facilities	Stip	2.1.1	Environmental Briefing	Satisfactory	Compliance
Milne Pt Oil	8/28/2008	Orientation tour BP facilities	Stip	2.4.6.1	Big Game Movement	Satisfactory	Compliance
Milne Pt Product	8/28/2008	Orientation tour BP facilities	Sec	6a	Reservations of Certain Rights to the State	Satisfactory	Compliance
Milne Pt Product	8/28/2008	Orientation tour BP facilities	Sec	8d	Covenants	Satisfactory	Compliance
Milne Pt Product	8/28/2008	Orientation tour BP facilities	Sec	15b	Conduct of Operations	Satisfactory	Compliance
Milne Pt Product	8/28/2008	Orientation tour BP facilities	Stip	1.11.2	Regulation of Access	Satisfactory	Compliance
Milne Pt Product	8/28/2008	Orientation tour BP facilities	Stip	1.12.1	Storage	Satisfactory	Compliance
Milne Pt Product	8/28/2008	Orientation tour BP facilities	Stip	2.1.1	Environmental Briefing	Satisfactory	Compliance
Milne Pt Product	8/28/2008	Orientation tour BP facilities	Stip	2.4.1	Big Game Movement	Satisfactory	Compliance
Milne Pt Product	8/28/2008	Orientation tour BP facilities	Sec	4d	Covenants	Satisfactory	Compliance
Endicott	8/28/2008	Orientation tour BP facilities	Sec	7a	Reservations of Certain Rights to the State	Satisfactory	Compliance
Endicott	8/28/2008	Orientation tour BP facilities	Stip	1.3.6	Responsibilities	Satisfactory	Compliance
Endicott	8/28/2008	Orientation tour BP facilities	Stip	1.11.1	Health & Safety	Satisfactory	Compliance

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Pipeline	Trip or Review Date	Topic	Sec/ Strip	Number	Sec/Stip Title	Observation	SPCO Section
Endicott	8/28/2008	Orientation tour BP facilities	Stip	1.17.1	Regulation of Access	Satisfactory	Compliance
Endicott	8/28/2008	Orientation tour BP facilities	Stip	2.1.1	Environmental Briefing	Satisfactory	Compliance
Endicott	8/28/2008	Orientation tour BP facilities	Stip	2.4.6.1	Big Game Movement	Satisfactory	Compliance
Badami Utility	8/28/2008	Orientation tour BP facilities	Sec	6a	Reservations of Certain Rights to the State	Satisfactory	Compliance
Badami Oil	8/28/2008	Orientation tour BP facilities	Sec	6a	Reservations of Certain Rights to the State	Satisfactory	Compliance
TAPS	9/3/2008	OMS Inventory	Stip	2.6	Material Sites	Satisfactory	ROW
TAPS	9/3/2008	OMS Inventory	Stip	2.6	Material Sites	Satisfactory	ROW
TAPS	9/3/2008	OMS Inventory	Stip	2.6	Material Sites	Minor	ROW
TAPS	9/3/2008	OMS Inventory	Stip	2.6	Material Sites	Satisfactory	ROW
TAPS	9/3/2008	OMS Inventory	Stip	2.6	Material Sites	Satisfactory	ROW
TAPS	9/3/2008	OMS Inventory	Stip	2.6	Material Sites	Satisfactory	ROW
TAPS	9/3/2008	OMS Inventory	Stip	2.6	Material Sites	Satisfactory	ROW
TAPS	9/3/2008	OMS Inventory	Stip	2.6	Material Sites	Satisfactory	ROW
TAPS	9/3/2008	OMS Inventory	Stip	2.6	Material Sites	Minor	ROW
TAPS	9/16/2008	Safety Inspection	Stip	1.20	Health and Safety	COTS	DOLWD
TAPS	9/16/2008	Safety Inspection	Stip	1.20	Health and Safety	COTS	DOLWD
TAPS	9/16/2008	Safety Inspection	Stip	1.20	Health and Safety	Satisfactory	DOLWD
TAPS	9/16/2008	Safety Inspection	Stip	1.20	Health and Safety	Satisfactory	DOLWD
TAPS	9/16/2008	Safety Inspection	Stip	1.20	Health and Safety	Satisfactory	DOLWD
TAPS	9/16/2008	Safety Inspection	Stip	1.20	Health and Safety	COTS	DOLWD
TAPS	9/16/2008	Safety Inspection	Stip	1.20	Health and Safety	Satisfactory	DOLWD
TAPS	9/16/2008	Safety Inspection	Stip	1.20	Health and Safety	Satisfactory	DOLWD
TAPS	9/17/2008	Safety Inspection	Stip	1.20	Health and Safety	Satisfactory	DOLWD
TAPS	11/13/2008	Safety Inspection	Stip	1.20	Health and Safety	Satisfactory	DOLWD / Compliance
TAPS	11/13/2008	Safety Inspection	Stip	1.20	Health and Safety	Satisfactory	DOLWD / Compliance
TAPS	11/13/2008	Safety Inspection	Stip	1.20	Health and Safety	Satisfactory	DOLWD / Compliance
KKPL	1/23/2009	Annual Report Review	Stip	1.13.1	Reporting	Satisfactory	Compliance

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Pipeline	Trip or Review Date	Topic	Sec/ Stip	Number	Sec/Stip Title	Observation	SPCO Section
TAPS	2/2/2009	Safety Inspection	Stip	1.20	Health and Safety	Satisfactory	DOLWD
TAPS	2/2/2009	Safety Inspection	Stip	1.20	Health and Safety	Satisfactory	DOLWD
TAPS	2/2/2009	Safety Inspection	Stip	1.20	Health and Safety	Satisfactory	DOLWD
TAPS	2/2/2009	Safety Inspection	Stip	1.20	Health and Safety	Satisfactory	DOLWD
TAPS	2/2/2009	Safety Inspection	Stip	1.20	Health and Safety	COTS	DOLWD
TAPS	2/2/2009	Safety Inspection	Stip	1.20	Health and Safety	Satisfactory	DOLWD
TAPS	2/2/2009	Safety Inspection	Stip	1.20	Health and Safety	Satisfactory	DOLWD
TAPS	2/2/2009	Safety Inspection	Stip	1.20	Health and Safety	COTS	DOLWD
TAPS	2/2/2009	Safety Inspection	Stip	1.20	Health and Safety	Satisfactory	DOLWD
TAPS	2/2/2009	Safety Inspection	Stip	1.20	Health and Safety	COTS	DOLWD
TAPS	2/2/2009	Safety Inspection	Stip	1.20	Health and Safety	COTS	DOLWD
KPE	2/9/2009	KPE Pipe Replacement	Stip	1.3.6	Responsibilities	Satisfactory	Compliance
KPE	2/9/2009	KPE Pipe Replacement	Stip	1.9.1	Conduct of Operations	Satisfactory	Compliance
KPE	2/9/2009	KPE Pipe Replacement	Stip	1.10.1	Surveillance & Maintenance	Satisfactory	Compliance
KPE	2/9/2009	KPE Pipe Replacement	Stip	1.17.1	Regulations of Access	Satisfactory	Compliance
KPE	2/9/2009	KPE Pipe Replacement	Stip	1.18.1	Use of Existing Facilities	Satisfactory	Compliance
Badami Oil	2/20/2009	Annual Report Review	Stip	1.6.2	Surveillance and Monitoring	Satisfactory	Compliance
Badami Utility	2/20/2009	Annual Report Review	Stip	1.6.2	Surveillance and Monitoring	Satisfactory	Compliance
Endicott	2/20/2009	Annual Report Review	Sec	4c	Covenants	Satisfactory	Compliance
Endicott	2/20/2009	Annual Report Review	Stip	1.8.3	Quality assurance & control	Satisfactory	Compliance
Endicott	2/20/2009	Annual Report Review	Stip	1.10.1	Surveillance & Maintenance	Satisfactory	Compliance
Milne Pt Oil	2/20/2009	Annual Report Review	Sec	4c	Covenants	Satisfactory	Compliance
Milne Pt Oil	2/20/2009	Annual Report Review	Stip	1.8.3	Quality assurance & control	Satisfactory	Compliance
Milne Pt Oil	2/20/2009	Annual Report Review	Stip	1.10.1	Surveillance & Maintenance	Satisfactory	Compliance
Milne Pt Product	2/20/2009	Annual Report Review	Stip	1.13.1	Reporting	Satisfactory	Compliance
Northstar Gas	2/20/2009	Annual Report Review	Stip	1.14.1	Reporting	Satisfactory	Compliance
Northstar Oil	2/20/2009	Annual Report Review	Stip	1.14.1	Reporting	Satisfactory	Compliance
Kuparuk	3/10/2009	Annual Report Review	Sec	4c	Covenants	Satisfactory	Compliance
Kuparuk	3/10/2009	Annual Report Review	Stip	1.3.3	Responsibilities	Satisfactory	Compliance
Kuparuk	3/10/2009	Annual Report Review	Stip	1.8.3	Quality assurance & control	Satisfactory	Compliance
Kuparuk	3/10/2009	Annual Report Review	Stip	1.10.1	Surveillance & Maintenance	Satisfactory	Compliance

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Pipeline	Trip or Review Date	Topic	Sec/ Stip	Number	Sec/Stip Title	Observation	SPCO Section
KPE	3/10/2009	Annual Report Review	Sec	4c	Covenants	Satisfactory	Compliance
KPE	3/10/2009	Annual Report Review	Stip	1.3.3	Responsibilities	Satisfactory	Compliance
KPE	3/10/2009	Annual Report Review	Stip	1.8.3	Quality assurance & control	Satisfactory	Compliance
KPE	3/10/2009	Annual Report Review	Stip	1.10.1	Surveillance & Maintenance	Satisfactory	Compliance
Oliktok	3/10/2009	Annual Report Review	Stip	1.3.3	Responsibilities	Satisfactory	Compliance
KPE	3/11/2009	KPE Pipe Replacement	Sec	4c-d	Covenants	Satisfactory	Compliance
KPE	3/11/2009	KPE Pipe Replacement	Sec	10	Duty of Lessee to prevent or abate	Satisfactory	Compliance
KPE	3/11/2009	KPE Pipe Replacement	Stip	1.3.6	Responsibilities	Satisfactory	Compliance
KPE	3/11/2009	KPE Pipe Replacement	Stip	1.9.1	Conduct of Operations	Satisfactory	Compliance
KPE	3/11/2009	KPE Pipe Replacement	Stip	1.17.1	Regulation of Access	Satisfactory	Compliance
Oliktok	3/13/2009	Annual Report Review	Sec	4c	Covenants	Satisfactory	Compliance
Oliktok	3/13/2009	Annual Report Review	Stip	1.8.3	Quality assurance & control	Satisfactory	Compliance
Oliktok	3/13/2009	Annual Report Review	Stip	1.10.1	Surveillance & Maintenance	Satisfactory	Compliance
Nuiqsut	3/25/2009	Annual Report Review	Stip	1.14.1	Reporting	Minor	Compliance
TAPS	3/25/2009	Safety Inspection PS 4 SR	Stip	1.20	Health and Safety	Satisfactory	DOLWD
TAPS	4/1/2009	Safety Inspection at Integrity Dig	Stip	1.20	Health and Safety	Satisfactory	DOLWD / Compliance
Alpine Diesel	4/8/2009	Annual Report Review	Stip	1.14.1	Reporting	Satisfactory	Compliance
Alpine Oil	4/8/2009	Annual Report Review	Stip	1.14.1	Reporting	Satisfactory	Compliance
Alpine Utility	4/8/2009	Annual Report Review	Stip	1.14.1	Reporting	Satisfactory	Compliance
TAPS	4/28/2009	Safety Inspection	Stip	1.20	Health and Safety	COTS	DOLWD
TAPS	4/28/2009	Safety Inspection	Stip	1.20	Health and Safety	Satisfactory	DOLWD
TAPS	4/28/2009	Safety Inspection	Stip	1.20	Health and Safety	Satisfactory	DOLWD
TAPS	4/28/2009	Safety Inspection	Stip	1.20	Health and Safety	Satisfactory	DOLWD
TAPS	4/28/2009	Safety Inspection	Stip	1.20	Health and Safety	Satisfactory	DOLWD
TAPS	4/28/2009	Safety Inspection	Stip	1.20	Health and Safety	Satisfactory	DOLWD
TAPS	4/28/2009	Safety Inspection	Stip	1.20	Health and Safety	COTS	DOLWD
TAPS	4/28/2009	Safety Inspection	Stip	1.20	Health and Safety	COTS	DOLWD
TAPS	4/28/2009	Safety Inspection	Stip	1.20	Health and Safety	Satisfactory	DOLWD
TAPS	4/28/2009	Safety Inspection	Stip	1.20	Health and Safety	Satisfactory	DOLWD
TAPS	4/28/2009	Safety Inspection	Stip	1.20	Health and Safety	Satisfactory	DOLWD
TAPS	4/28/2009	Safety Inspection	Stip	1.20	Health and Safety	Satisfactory	DOLWD
TAPS	4/28/2009	Safety Inspection	Stip	1.20	Health and Safety	Satisfactory	DOLWD

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Pipeline	Trip or Review Date	Topic	Sec/ Stip	Number	Sec/Stip Title	Observation	SPCO Section
TAPS	5/11/2009	Orientation	Stip	1.19.1	Housing and Quarters	Satisfactory	Compliance
TAPS	5/11/2009	Orientation	Stip	1.20.1	Health and Safety	Satisfactory	Compliance
TAPS	5/11/2009	Orientation	Stip	1.21.1	Conduct of Operations	Satisfactory	Compliance
TAPS	5/11/2009	Orientation	Stip	2.2.1.1	Pollution Control	Satisfactory	Compliance
TAPS	5/11/2009	Orientation	Sec	6a	Access to Property, Books and Records	Satisfactory	Compliance
TAPS	5/11/2009	Orientation	Sec	10a	Damage or Destruction of Leasehold or Other Property	Satisfactory	Compliance
TAPS	5/11/2009	Orientation	Sec	16	Quality Assurance	Satisfactory	Compliance
TAPS	5/11/2009	Orientation	Sec	17a	Reservation of Certain Rights to the State	Satisfactory	Compliance
TAPS	5/11/2009	Orientation	Sec	22a	Duty of Lessee to Prevent or Abate	Satisfactory	Compliance
TAPS	5/12/2009	Safety Inspection	Stip	1.20	Health and Safety	Satisfactory	DOLWD
TAPS	5/12/2009	Safety Inspection	Stip	1.20	Health and Safety	Satisfactory	DOLWD
KKPL	5/19/2009	Document Check/ROW	Sec	1	Lease of ROW	Satisfactory	Compliance
KKPL	5/19/2009	Document Check/ROW	Sec	6	Reservation of Certain Rights	Satisfactory	Compliance
KKPL	5/19/2009	Document Check/ROW	Sec	8	Covenants	Satisfactory	Compliance
KKPL	5/19/2009	Document Check/ROW	Sec	15	Conduct of Operations	Satisfactory	Compliance
KKPL	5/19/2009	Document Check/ROW	Sec	16	Environmental Compliance	Satisfactory	Compliance
KKPL	5/19/2009	Document Check/ROW	Sec	20	Information	Satisfactory	Compliance
KKPL	5/19/2009	Document Check/ROW	Stip	1.2.1	Communications	Satisfactory	Compliance
KKPL	5/19/2009	Document Check/ROW	Stip	1.5.1	Conduct of Operations	Satisfactory	Compliance
KKPL	5/19/2009	Document Check/ROW	Stip	1.11.2	Regulation of Access	Satisfactory	Compliance
KKPL	5/19/2009	Document Check/ROW	Stip	1.12	Storage	Satisfactory	Compliance
KKPL	5/19/2009	Document Check/ROW	Stip	2.2.1	Erosion and Sedimentation Control	Satisfactory	Compliance
KKPL	5/19/2009	Document Check/ROW	Stip	2.8.2	Reporting, Prevention, Control, Cleanup, & Disposal of Oil & Hazardous Substance Discharges	Satisfactory	Compliance
TAPS	5/27/2009	Culvert Inspection	Stip	2.4, 2.5.1.1, 2.12.1	Crossing of Streams, River or Flood Plains, Seeding and Planting, Passage of Fish, and Restoration	Satisfactory	ADF&G
TAPS	5/27/2009	LWC Inspection	Stip	2.4, 2.5.1.1, 2.12.1		Satisfactory	ADF&G
TAPS	5/27/2009	LWC Inspection	Stip	2.4, 2.5.1.1, 2.12.1		Satisfactory	ADF&G
TAPS	5/27/2009	Culvert Inspection	Stip	2.4, 2.5.1.1, 2.12.1		Satisfactory	ADF&G
TAPS	5/27/2009	LWC Inspection	Stip	2.4, 2.5.1.1, 2.12.1		Satisfactory	ADF&G
TAPS	5/27/2009	LWC Inspection	Stip	2.4, 2.5.1.1, 2.12.1		COTS	ADF&G
TAPS	5/27/2009	LWC Inspection	Stip	2.4, 2.5.1.1, 2.12.1		Satisfactory	ADF&G
TAPS	5/27/2009	Culvert Inspection	Stip	2.4, 2.5.1.1, 2.12.1		Satisfactory	ADF&G

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Pipeline	Trip or Review Date	Topic	Sec/ Strip	Number	Sec/Stip Title	Observation	SPCO Section
Nikiski	6/1/2009	Document Check	Sec	1c	Grant of Right-of-Way	Satisfactory	Compliance
Nikiski	6/1/2009	Document Check	Sec	6	Books, Accounts & Reports Access to Property & Records	Satisfactory	Compliance
Nikiski	6/1/2009	Document Check	Sec	9(a)(b)	Damage or Destruction of Leasehold or other Property	Satisfactory	Compliance
Nikiski	6/1/2009	Document Check	Sec	17	Reservation of Certain Rights	Satisfactory	Compliance
Nikiski	6/1/2009	Document Check	Sec	19	Duty of Lessee to Prevent or Abate	Satisfactory	Compliance
Nikiski	6/1/2009	Document Check	Stip	1.11.1	Public Improvements	Satisfactory	Compliance
Nikiski	6/1/2009	Document Check	Stip	1.16.1	Conduct of Operations	Satisfactory	Compliance
Nikiski	6/1/2009	Document Check	Stip	2.2.1.1	Erosion Control: General	Satisfactory	Compliance
TAPS	6/3/2009	Safety Inspection	Stip	1.20	Health and Safety	Satisfactory	DOLWD
TAPS	6/17/2009	LWC Inspection	Stip	2.4, 2.5.1.1, 2.12.1	Crossing of Streams, River or Flood Plains, Seeding and Planting, Passage of Fish, and Restoration	Satisfactory	ADF&G
TAPS	6/17/2009	Culvert Inspection	Stip	2.4, 2.5.1.1, 2.12.1		Satisfactory	ADF&G
TAPS	6/17/2009	LWC Inspection	Stip	2.4, 2.5.1.1, 2.12.1		Satisfactory	ADF&G
TAPS	6/17/2009	LWC Inspection	Stip	2.4, 2.5.1.1, 2.12.1		Satisfactory	ADF&G
TAPS	6/17/2009	LWC Inspection	Stip	2.4, 2.5.1.1, 2.12.1		Satisfactory	ADF&G
TAPS	6/17/2009	LWC Inspection	Stip	2.4, 2.5.1.1, 2.12.1		Satisfactory	ADF&G
TAPS	6/17/2009	Revetment Inspection	Stip	2.4, 2.5.1.1, 2.12.1		Satisfactory	ADF&G
TAPS	6/17/2009	LWC Inspection	Stip	2.4, 2.5.1.1, 2.12.1		Satisfactory	ADF&G
TAPS	6/17/2009	Guidebank Inspection	Stip	2.4, 2.5.1.1, 2.12.1		Satisfactory	ADF&G
TAPS	6/17/2009	Culvert Inspection	Stip	2.4, 2.5.1.1, 2.12.1		Satisfactory	ADF&G
TAPS	6/17/2009	Revetment Inspection	Stip	2.4, 2.5.1.1, 2.12.1		Satisfactory	ADF&G
TAPS	6/17/2009	Boat Launch inspection	Stip	2.4, 2.5.1.1, 2.12.1		Satisfactory	ADF&G
Badami Oil	6/24/2009	Local Hire	Sec	28	Local Hire	Satisfactory	Compliance
Badami Utility	6/24/2009	Local Hire	Sec	28	Local Hire	Satisfactory	Compliance
Milne Pt Product	6/24/2009	Local Hire	Sec	32	Local Hire	Satisfactory	Compliance
Northstar Gas	6/24/2009	Local Hire	Sec	32	Local Hire	Satisfactory	Compliance
Northstar Oil	6/24/2009	Local Hire	Sec	32	Local Hire	Satisfactory	Compliance

Appendix J – SPCO Annual Reporting Requirements for Lessees

In addition to lease-specific requirements, the SPC has required each lessee to provide an annual comprehensive report that includes, at a minimum:

1. The results of the lessee's surveillance & monitoring program during the preceding year, including annual and cumulative changes in facilities and operations, the effects of the changes, and proposed actions to be taken as a result of the noted changes:
   - *Provide a summary of the scope of all surveillances, audits, self-assessments or other internal evaluations performed by the lessee.*
   - *Summarize findings, action items and other observations identified as a result of all surveillances, audits, self-assessments or other internal evaluations performed by the lessee.*
   - *Describe corrective and preventative actions planned or implemented as a result of surveillances, audits, self-assessments or other internal evaluations performed by the lessee.*
   - *To the extent known, list by quarter, those surveillances, audits, self-assessments or other internal evaluations planned for next year.*
2. The state of, changes to, and results from the last year of the lessee's risk management program, quality assurance program, and internal and external safety programs.
3. Lessee's performance under the right-of-way lease, including stipulations.
4. Information on construction, operations, maintenance, and termination activities necessary to provide a complete and accurate representation of the lessee's activities and the state of the pipeline system.
5. A summary of all events, incidents and issues which had the potential to or actually did adversely impact pipeline system integrity, the environment, or worker or public safety and a summary of the lessee's response.
6. A summary of all oil and hazardous substance discharges including date, substance, quantity, location, cause, and cleanup actions undertaken. Minor discharges below agreed upon thresholds may be grouped into monthly total amounts, provided the number of separate incidents is reported.

Any additional information requested by the State Pipeline Coordinator.

Appendix K – Throughput for SPCO Jurisdictional Pipelines*

Badami Sales Oil	Not in service
Badami Utility	Not in service
Endicott (Oil)	5,481,023 net barrels
Kenai Kachemak Pipeline (Natural Gas)	21.77 MMcfpd
Milne Point Pipeline (Oil)	11,801,237 net barrels
Milne Point Product Pipeline (NGL)	Not in service
Nikiski Alaska (Refined Products)	11,400,129 barrels
Northstar Oil	11,440,587 net barrels
Northstar Gas	17,286,081 Mscf.
Nuiqsut Natural Gas Pipeline	16,976.36 mcf
Trans-Alaska Pipeline System (Oil)	257,499,836 barrels

** Pipelines operated by CPAI are not included in this table.*

Appendix L – Sources of More Information on the Internet

Other State Agencies Outside of the SPCO

The Alaska Department of Transportation/Public Facilities (DOT/PF) is a coordinating agency that does not currently have any staff co-located within the JPO. The Regulatory Commission of Alaska (RCA) and the Alaska Department of Revenue both have roles in common carrier oversight, while not being integrated members of the JPO or SPCO.

The Petroleum Systems Integrity Office (PSIO) within the DNR Division of Oil and Gas (DOG) is also not a part of the SPCO, although the offices coordinate regularly on oil and gas pipeline issues in Alaska. PSIO and SPCO field personnel will share information about conditions they have observed in the field that apply to the other agency's jurisdiction.

State Agencies

Alaska Oil & Gas Conservation Commission
http://www.aogcc.alaska.gov

Dept. of Environmental Conservation,
Division of Spill Prevention and Responses,
Industry Preparedness Program
http://www.dec.state.ak.us/spar/ipp/index.htm

Dept. of Fish and Game, Habitat Division
http://www.habitat.adfg.alaska.gov/

Dept. of Labor & Workforce Development,
Division of Labor Standards and Safety,
http://www.labor.state.ak.us/lss/home.htm

Dept. of Natural Resources,
Div. of Coastal & Ocean Mgmt.
http://dnr.alaska.gov/coastal/

Department of Natural Resources,
Division of Oil and Gas
http://www.dog.dnr.state.ak.us/oil/

Department of Public Safety,
State Fire Marshall's Office
http://www.dps.state.ak.us/Fire/

Dept. of Transportation and Public Facilities
http://www.dot.state.ak.us

Regulatory Commission of Alaska
https://rca.alaska.gov/RCAWeb/AboutRCA/Commission.aspx

State Pipeline Coordinator's Office
http://www.jpo.doi.gov/SPCO/SPCO.htm

Federal Agencies

Office of the Federal Coordinator
Alaska Natural Gas Transportation Projects
http://www.arcticgas.gov

Joint Pipeline Office
http://www.jpo.doi.gov

US Army Corps of Engineers: Alaska District
http://www.poa.usace.army.mil/ht/default.htm

US Coast Guard:17th District
http://www.uscgalaska.com/go/site/780/

US Department of the Interior:
Bureau of Land Management, Alaska
http://www.blm.gov/ak/st/en.html

US Department of Labor:
Occupational Safety & Health Administration
http://www.osha.gov

US Department of Transportation
http://www.dot.gov

US Department of Transportation:
Pipeline and Hazardous Materials Safety Administration
http://www.phmsa.dot.gov/

US Environmental Protection Agency:
Region 10: The Pacific Northwest
http://www.epa.gov/region10/

US Fish & Wildlife Service
http://www.fws.gov